OGCB REPORT 69-F

IN THE MATTER OF AN APPLICATION OF TRANS-CANADA PIPELINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

Alta

OIL AND GAS CONSERVATION BOARD

603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

REPORT TO

THE LIEUTENANT GOVERNOR IN COUNCIL

IN THE MATTER OF AN APPLICATION OF TRANS-CANADA PIPELINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

NOVEMBER 1969

OIL AND GAS CONSERVATION BOARD

603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

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I INTRODUCTION

The subject application, made by Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956, was heard on June 24, 1969, with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng. and Vernon Millard sitting.

Trans-Canada applied to have its permit No. TC 68-8 amended and the permit and amendments together with its Permit No. PG 64-1 consolidated into a new permit. The proposed amendments more fully set out in Section II of this report, would extend the term of the permit, increase the permit volumes and add to the list of pools, fields and areas from which gas may be taken for removal from the Province.

Date of Reserve Assessment, Period of Protection and Method of Assessment of Provincial Surplus

The application contained Trans-Canada's reserve estimates as of February 28, 1969. At the hearing Trans-Canada asked that, for the purposes of the application, the Board update its reserve estimates to May 31, 1969, and the Board has assessed the reserves of the Province as of this date.

The period for which the Board has assessed the requirements of the Provine is 30 years commencing June 1, 1969.

The Board, following the hearing which began June 17, 1969, of an application by the Alberta Division of the Canadian Petroleum Association for reconsideration of the policies and procedures of the Board for considering applications made under The Gas Resources Preservation Act, 1956, issued its report

OGCB 69-D[1]. This report, among other things, sets forth revised policies and procedures for considering such applications. The Board has applied the revised policies and procedures in assessing whether or not the subject application should be granted.

Standard Conditions of Measurement

In this report, unless otherwise stated, volumes of gas are at the standard conditions of 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Where reserves of gas are referred to herein, it means, unless otherwise specified, marketable reserves.

Appearances

The persons listed in Table 1 appeared at the hearing. Alberta and Southern, the City of Calgary, the City of Edmonton, Consolidated and Westcoast intervened for the purposes of cross-examination and argument only.

Alix Field, Bantry Field and Clive Field

It appeared that the facilities to gather solution gas for the Alix Field, Bantry Field and Clive Field, which were among those which Trans-Canada applied to have named in its permit, would be completed by about August 1, 1969. In view of the conservation gain that would be achieved by including these fields in the permit, the Board considered the advisability

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

of making this change prior to completing consideration of the application. The Board noted that

(a) no objection had been submitted to the naming of these fields in the permit,

(b) the fields were adjacent to facilities then being used to deliver gas to Trans-Canada,

(c) the total gas in the three fields which would be removed under the permit would be some 136 billion cubic feet,

(d) the addition of the fields, without other amendment to the permit, would not increase the amount of the gas that could be removed pursuant to the permit,

(e) the addition of the fields to those named in the permit would make possible the utilization of some 6.7 million cubic feet per day of gas that was currently being flared, and

(f) the addition of the fields to the permit would make possible an alleviation of pollution problems caused by the flaring of the solution gas.

On August 7, 1969, the Board with the approval of the Lieutenant Governor in Council, amended Permit No. TC 68-8 by adding to the list of pools, fields and areas therein the Alix Field, the Bantry Field and the Clive Field.

TABLE I

	Abbreviation of Name Used in Report	Represented by	Witnesses
Trans-Canada Pipe Lines Limited	Trans-Canada	J. M. Cameron R. J. Ludgate	G. A. Leslie, P.Geol. L. H. Larson, P.Geol. R. B. Trimble, P.Eng.
Alberta and Southern Gas Co. Ltd.	Alberta and Southern	M. A. Putnam	
Canadian Western Natural Gas Company Limited and North-western Utilities, Limited	Utility Companies	G.A.C. Steer, Q.C.	J. E. Maybin, P.Eng.
City of Calgary City of Edmonton	Cities	S. J. Helman, Q.C. A. F. Macdonald, Q.C.	
Consolidated Natural Gas Limited	Consolidated	J. H. Laycraft, Q.C.	
Gulf Oil Canada Limited	Gulf	J. A. Nikolaychuk, P.Eng.	J. A. Nikolaychuk, P.Eng. G. W. Fawcett J. F. Milne, P. Geol.
Westcoast Transmission Company Limited	Westcoast	J. Lutes	
Pacific Petroleums Ltd.	Pacific	G. W. Lade	G. D. Nickoloff, P. Eng.
Board Staff		F. Phillips, P.Eng. G. A. Warne, P. Eng.	

II SUBMISSION OF TRANS-CANADA PIPE LINES LIMITED

Trans-Canada applied for the amendment of Permit TC 68-8 by

(a) extending its term by one year to October 31, 1994,

(b) increasing the volume of gas that may be removed in a 24-hour period by 195 million cubic feet to 2,910,000,000 cubic feet,

(c) increasing the volume of gas that may be removed annually by 72 billion cubic feet to 932,000,000,000 cubic feet,

(d) increasing the volume of gas that may be removed during the term of the permit by 2.2 trillion cubic feet to 21.4 trillion cubic feet,

(e) striking out clause 3 of the terms and conditions and substituting:

"3. The quantity of gas that may be removed from the Province, in accordance with Clause 2, sub-clause (b), during any twelve-month period ending October 31, may be augmented by all or any part of the quantity of gas which is obtained by subtracting the quantity of gas that was removed from the Province in the last preceding four-year period ending October 31, from the quantity of gas which the Applicant was authorized to remove from the Province during such four-year period, but nothing herein authorizes the removal of gas from the Province in any consecutive twenty-four hour period or during the term of the Permit in excess of the volumes stipulated for such periods in Clause 2."

(f) adding to the list of fields, pools and areas from which gas may be removed from the Province the following:

"Alix	Lake Newell	South Bassano
Bantry	Long Coulee South	Strachan
Birch Lake	Mikwan	Whiskey Creek
Bragg Creek	Moose Mountain	Willesden Green
Clive	Obed	Winnifred"
East Bellis	Parflesh	
Jenner	Plain Lake	

and

(g) further amending and revising Permit No. TC 68-8 to include therein the permitted fields authorized in Permit No. PG 64-1, and consolidating therein Permit No. PG 64-1.

At the hearing Trans-Canada stated that the reserve development in the Black Diamond Field had been insufficient to justify connection of the Alberta Gas Trunk Line Company system. Trans-Canada agreed with the producers in the field that the gas from the field should be made available to the local utilities, and had allowed its development contracts to terminate. It stated the field therefore should be removed from its permit. However, subsequent to the hearing Trans-Canada advised that it had reassessed this matter as discussed below under "Reserves under Contract".

Trans-Canada included in its submission a letter in which The Alberta Gas Trunk Line Company Limited stated that it is prepared to construct the facilities necessary to transport the additional volumes applied for.

Reserves

Trans-Canada estimated the initial marketable reserves available to it in the fields now in its Permit No. TC 68-8, in its Permit No. PG 64-1, and in the new areas applied for to be some 22.7 trillion cubic feet and that 96 per cent of the reserves are proved reserves. The reserves comprise some 2.8 trillion cubic feet in new areas and 19.9 trillion cubic feet in fields named in Permit No. TC 68-8 and Permit No. PG 64-1.

In assessing total provincial reserves Trans-Canada did not estimate the reserves of each individual field, pool and area. However, it estimated the reserves of those areas in which significant developments, not reflected in the Board's last estimate had occurred or for which it differed appreciably with the Board's interpretation of a reserve. On this basis, the applicant estimated that at February 28, 1969, the remaining established reserves of the Province were 44.7 trillion cubic feet of gas, or 46.9 trillion cubic feet on a 1000 British Thermal Units (Btu) per cubic foot equivalent basis.

Trans-Canada's estimate of the reserves of the Province was obtained by taking the Board's estimate of the reserves of the Province as of May 31, 1968, as modified to August 31, 1968, by OGCB Report 69-A[1], and adjusting the estimate to February 28, 1969, for

(a) the growth in reserves in the interim in the fields, pools and areas, the gas from which it has contracted to purchase, and

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(1) In the Matter of an Application of Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. February,1969.

(b) the growth in other fields and areas where it has observed significant reserve changes, and

(c) the production which has occurred since the earlier estimate.

It concluded that the reserves of fields and pools not included in its permits have increased at least 0.4 trillion cubic feet during the period August 31, 1968 to February 28, 1969. It emphasized that this quantity did not include any estimate for the new discoveries in the Ricinus area. Trans-Canada added that the Board had details of new discoveries and it expected the Board's reserve estimate would reflect such information.

Trans-Canada submitted that, having regard to current developments and recent extensions to the system of The Alberta Gas Trunk Line Company Limited, the reserves of the Big Bend Field, the Calling Lake Field, the Richdale Field, and the Obed and Plain Lake areas, should now be considered within economic reach. After adjusting the Board's estimate for these changes it determined that the reserves presently beyond economic reach are 2,646 billion cubic feet.

A detailed discussion of Trans-Canada's estimate and comparative estimates of the Board is presented in Appendix A.

Reserves under Contract

Trans-Canada submitted that it had under contract some 96 per cent of the gas it estimated was not committed to others in the fields now in its permits. It added that of the new reserves it wishes added to its principal permit, including those in

Permit No. PG 64-1, some 94 per cent are under contract to it, and that a significant portion of the reserves in each of such areas named in the application is under contract to it.

Trans-Canada said at the hearing that its contracts in the Black Diamond Field had been terminated. However, after the hearing it informed the Board that it was renewing its contracts in the Black Diamond Field and would like the Field to be left in its permit.

Trans-Canada submitted deliverability schedules showing that during the term of the permit, if extended in accordance with the application, essentially all of the 21.4 trillion cubic feet, the new total volume of its permit, would be produced from the fields now in the permits and from the new fields it applied to have added to the permit.

Trend in Growth of Reserves

The applicant submitted that the long term trend in the growth of the initial marketable reserves of the Province has been 2.7 trillion cubic feet per year and the growth rate over the previous two years has been 4.1 trillion cubic feet per year.

The long term growth trend was determined from the initial marketable reserves of the Province at February 28, 1969, which Trans-Canada determined to be 53.2 trillion cubic feet, and at June 30, 1955, which the Board estimated to be 15.9 trillion cubic feet. The growth rate over the previous two years was determined from the applicant's current estimate of the initial marketable reserves and the Board's estimate as at December 31,

1966, of 44.4 trillion cubic feet.

Further discussion of Trans-Canada's assessment of the trend in the growth of reserves is included in Appendix B.

Requirements

Trans-Canada did not present its own forecast of Alberta's 30-year requirements but updated the Board forecast published in OGCB Report 69-A to relate to the period March 1, 1969, to March 1, 1999.

Additional discussion of Trans-Canada's submission respecting requirements is included in Appendix C.

Surplus

Trans-Canada submitted that, using the method of calculation outlined in recent Board reports to that time, an overall surplus of 4.3 trillion cubic feet of 1000 Btu gas existed in the Province at February 28, 1969. It submitted that the contractable surplus was 3.1 trillion cubic feet and the future surplus was 1.2 trillion cubic feet, assuming that two years growth of gas reserves at the long term rate of 2.7 trillion cubic feet per year would be used to help meet the future or remaining requirements of the Province.

Details of Trans-Canada's surplus calculations appear in Appendix D.

III SUBMISSIONS OF INTERVENERS

Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited

The Utility Companies had no objection to the application if the Oil and Gas Conservation Board should find by using the method of assessment, under which the applicant has filed its application, that there are sufficient volumes of reserves surplus to the needs of the Province. The Utility Companies would also have no objection if the application were granted if the Board was satisfied the application met the conditions for granting such applications which the Utility Companies proposed in their submission to the hearing of the application of the Alberta Division of the Canadian Petroleum Association which hearing began June 17, 1969. That hearing considered the policies and procedures of the Board for considering applications made under The Gas Resources Preservation Act, 1956.

The Utility Companies advised that they had reached an agreement in principle with Trans-Canada regarding the removal from the Province of gas from portions of the Jumping Pound West Field and had no objection to the naming of a further pool in the Bragg Creek area near Jumping Pound West in Trans-Canada's permit.

The Utility Companies have adjusted their forecast of Alberta market requirements of natural gas submitted to the hearing of the Trans-Canada application in March, 1966. The adjustment reflects the increased requirements of the 30-year period 1969-1998 of 12.9 trillion cubic feet as compared with the 30-year period

1966-1995. The estimate does not include any allowance for Alberta Gas Trunk Line fuel or for the fuel and shrinkage requirements of the Empress and Cochrane reprocessing plants.

Gulf Oil Canada Limited

Gulf supported the part of the application for the naming of the Strachan area in Trans-Canada's permit and submitted its estimate of the reserves of the Leduc (D-3) zone in the area. It interpreted the D-3 zone to contain 1,593 billion cubic feet of marketable gas.

Gulf further submitted that the pentanes plus content of the reservoir fluid ranged from 21 to 27 barrels per million cubic feet and that calculations of the retrograde behaviour indicated retrograde losses in the reservoir in the absence of cycling would amount to only about one barrel per million cubic feet. Gulf submitted that in view of the relatively low retrograde losses indicated, cycling of the reservoir is not warranted.

Pacific Petroleums Ltd.

Pacific supported the inclusion of the Ricinus area in the list of fields and areas from which Trans-Canada may remove gas from the Province. It estimated the reserves of the D-3 pool encountered at the Pacific Pan Am Ricinus 7-19-35-8 well to be 154 billion cubic feet of proved marketable gas.

Pacific stated that it had not yet been able to test the well but planned to conduct a test shortly. It added that it would obtain a sample of the reservoir fluid and conduct a retrograde study of it to determine the extent of any retrograde

losses which might occur. Pacific agreed to provide the results of these investigations to the Board as soon as feasible.

IV FINDINGS

The Board having heard publicly the application under The Gas Resources Preservation Act, 1956, of Trans-Canada Pipe Lines Limited, and having studied the evidence submitted by the applicant and the interveners at the public hearing, and having regard to the advice of its staff and to its own knowledge, finds as follows:

1. THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the established reserves of marketable gas remaining in the Province at May 31, 1969, to be some 44.3 trillion cubic feet, or the equivalent of 46.8 trillion cubic feet of 1000 Btu gas.

Of the latter total some 2.9 trillion cubic feet are now considered to be beyond economic reach and some 5.1 trillion cubic feet will have production deferred, leaving a contractable reserve of 38.8 trillion cubic feet of 1000 Btu gas.

The present estimate of 46.8 trillion cubic feet is some 1.0 trillion cubic feet more than the Board's estimate at December 31, 1968. The increase is largely due to development drilling and to evaluation of reserves from pool performance where significant pressure and production data has become available.

Details of the Board's estimates and a discussion of the more significant changes since the Board's analysis as at December 31, 1968, are presented in Appendix A.

2. THE LONG TERM GROWTH OF RESERVES OF GAS IN ALBERTA AND THE FUTURE RESERVES TO BE CONSIDERED

The long term growth of initial marketable reserves of gas due to new discoveries and to appreciation of previous discoveries has continued to average some 2.5 trillion cubic feet per year determined on the basis used in previous reports. However, the Board indicated in its report OGCB 69-D[1] that it would use a growth rate determined from growth over the immediately preceding ten years to determine the growth of gas reserves to be considered in determining the relationships of future reserves to future requirements. The Board did not make an estimate of the reserves of the Province at May 31, 1959. However, during the 116-month period, September 30, 1959 to May 31, 1969, reserves increased by 25.2 trillion cubic feet, equivalent to 2.6 trillion cubic feet per year.

The Board also indicated in OGCB 69-D that it would determine the number of years of growth of gas reserves used in the surplus calculation on the basis of the Province's estimated remaining reserve potential. The formula adopted by the Board results in the use of 4.5 years of reserve growth.

Since the growth rates over the last five years and over the last two years have averaged 3.0 trillion cubic feet per year and 3.6 trillion cubic feet per year respectively, and having regard for other relevant factors, the Board estimates the average growth rate of initial gas reserves over the next 4.5-year period

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October, 1969.

as 2.6 trillion cubic feet per year.

Under the policy set forth in OGCB 69-D,the Board in the present circumstances therefore recognizes 11.7 trillion cubic feet of future gas reserves comprising 4.5 years of growth in determining the relationship between future reserves and future requirements. Particulars of the determination of these volumes are set forth in Appendix B.

3. THE PRESENT AND FUTURE REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS

The Board estimates Alberta's requirements for the 30 years, June 1, 1969, to May 31, 1999, to be 15.7 trillion cubic feet of 1,000 Btu gas, with a peak day requirement in the 30th year of 3.5 billion cubic feet. The present estimate represents an increase of 1.1 trillion cubic feet in the total 30-year requirements since the Board's last estimate, which was for the period, September 1, 1968, to August 31, 1998.

The commitments remaining at May 31, 1969, associated with permits issued for removal of gas from the Province, total some 26.1 trillion cubic feet of 1000 Btu gas.

Details of the Board's estimates of Alberta's requirements and permit commitments are presented in Appendix C.

4. THE MEETING OF ALBERTA'S 30-YEAR REQUIREMENTS AND PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

The Board estimates that reserves totalling some 20.7 trillion cubic feet of 1000 Btu gas are necessary to meet the annual and peak day requirements of Alberta for the 30-year period, June 1,

1969 to May 31, 1999. Of this total 15.7 trillion cubic feet are required for actual deliveries and the remaining 5.0 trillion cubic feet are needed to meet the 30th year peak day.

The Board's estimate of 20.7 trillion cubic feet may be considered to consist of 8.1 trillion cubic feet of contractable requirements and 12.6 trillion cubic feet of remaining requirements, the latter being a measure of the reserves needed from sources not now under contract or connected to the Alberta market.

The Board estimates that 26.4 trillion cubic feet of 1000 Btu gas are required to meet the present permit commitments, of which some 0.3 trillion cubic feet represent the reserves needed to ensure deliverability in the terminal year for those permits under which it is contemplated that substantial daily withdrawals for which protection has historically been provided will continue to the end of the term.

When the contractable requirement of 8.1 trillion cubic feet and the gas needed to satisfy the permit commitments of 26.4 trillion cubic feet are deducted from the contractable reserve of 38.8 trillion cubic feet, a contractable surplus of 4.3 trillion cubic feet results.

The remaining and future reserves totalling some 19.3 trillion cubic feet consist of 5.1 trillion cubic feet of deferred gas which will be available within the 30-year period, 2.2 trillion cubic feet of gas now beyond economic reach but which the Board believes will be within economic reach and available within 30 years, 0.3 trillion cubic feet of reserves allocated to

provide for the peak day in permits which will be available at the termination of the permits and within 30 years, and 11.7 trillion cubic feet representing 4.5 years of growth of gas reserves at a growth rate of 2.6 trillion cubic feet per year. Comparing the total with the 12.6 trillion cubic feet of remaining Alberta requirements results in a surplus of 6.7 trillion cubic feet in the future category. This results after full provision for the 3.0 trillion cubic feet required from sources not now connected to meet Alberta's 30th-year peak day.

Details of the Board's analysis of these matters appear in Appendix D.

5. THE VOLUMES UNDER CONTRACT AND THE PERMIT VOLUMES APPLIED FOR

The Board is satisfied that Trans-Canada has under contract 95 per cent of the established reserves as estimated by the Board, within the fields, pools and areas or portions thereof, which it applied to have added to its permit. Furthermore, Trans-Canada has under contract a sufficient portion of the reserves in each field or area to warrant naming it in the permit.

6. THE APPLICATION FOR REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE APPLICATION WERE GRANTED

The additional volume applied for by Trans-Canada, 2.2 trillion cubic feet, consists of 0.7 trillion cubic feet from fields, pools, and areas named in its present permits and 1.5 trillion cubic feet from new fields, pools and areas. The Board disagrees with Trans-Canada's estimate of the reserves in some of the new fields

and some of those fields now in its permits. However, the Board finds that its estimate of the reserves in both groups of pools is 0.4 trillion cubic feet greater than the volume applied for.

If the application were granted, the reserves needed to meet the commitment of all permits would increase from the present 26.4 trillion cubic feet of 1000 Btu gas, of which 0.3 trillion cubic feet is for the protection of deliveries at the maximum daily rate authorized and anticipated in certain of the permits, to 28.6 trillion cubic feet. The contractable surplus would be reduced from 4.3 trillion cubic feet to 2.1 trillion cubic feet. The future surplus of 6.7 trillion cubic feet would remain unchanged.

The Board thus finds that the additional volumes of gas applied for are surplus to the requirements of the Province and the present permit commitments. The Board is satisfied that essentially all of the gas may be produced within a 25-year term although the maximum daily rate requested could not be sustained during the last few years of the term.

Details of the Board's analysis of these matters is presented in Appendix E.

7. THE CONSOLIDATION OF PERMITS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED AND THE ANNUAL WITHDRAWAL RATE

The Board finds that Trans-Canada has acquired Permit No. PG 64-1, by assignment duly consented to by the Board in accordance with the Act. The Board is satisfied that this permit should not remain, after assignment to Trans-Canada, in its present form.

The consolidation of the permit with Permit No. TC 68-8 would eliminate the need to amend it and would not involve any risk to the protection of Alberta consumers. Further it would give the permittee greater operating flexibility.

The Board does not believe Trans-Canada intended to alter the relationship between the annual withdrawal rate and the total permit quantity by the amendment it proposed to clause 3. However, the Board finds that the form of the clause previously used more precisely defines the volumes by which it would permit augmenting the annual maximum and, therefore, is not prepared to amend this clause in accordance with the application.

8. THE DISPOSITION OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED

Permit No. TC 68-8 was amended on August 7, 1969, by the addition of three fields which Trans-Canada applied to have added to the permit.

In the light of its findings and its responsibility under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to amend Permit No. TC 68-8 by increasing the volume of gas which Trans-Canada may remove from the Province by 2,155 billion cubic feet, by adding the additional new fields and areas applied for, by extending its terms to October 31, 1994, and by consolidating with it Permit No. PG 64-1; the permits and amendments to be consolidated in the form shown in Appendix F and subject to the terms

and conditions therein contained.

Respectfully submitted,

G. W. Govier, P. Eng.
Chairman

A. F. Manyluk, P. Eng.
Deputy Chairman

Vernon Millard
Board Member

Dated at Calgary, Alberta

this 17th day of November, A.D. 1969.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the remaining established reserves of marketable gas in Alberta at May 31, 1969, were 44.3 trillion cubic feet, or the equivalent of 46.8 trillion cubic feet of 1,000 Btu gas. The initial established reserves obtained by adding the cumulative production to May 31, 1969 of 8.9 trillion cubic feet were 53.2 trillion cubic feet. The estimate of remaining established reserves represents an increase on an actual heating value basis of some 1.0 trillion cubic feet since December 31, 1968, when the Board's estimate was 43.4 trillion cubic feet. On an actual heating value basis, Trans-Canada estimated that the remaining established reserves at February 28, 1969, were 44.7 trillion cubic feet. Trans-Canada submitted reserve estimates for 19 fields from which it has contracted to purchase gas, and for certain other fields where significant increases had occurred since the Board's assessments of May 31, and August 31, 1968, published in OGCB Report 68-A[1] and OGCB Report 69-A[2].

While only the established reserves are discussed in this report, the Board has calculated proved and probable reserves of gas. The definitions and interrelationships of these categories of reserves are as follows:

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(1) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

(2) In the Matter of an Application of Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. February, 1969.

<u>Proved Reserves</u> are the recoverable gas reserves within the area of a pool completely delineated by drilled wells. A portion of such reserves may be in undrilled drilling spacing units but so located structurally that there is every reasonable probability that the reserves will be produced by wells drilled or to be drilled.

<u>Probable Reserves</u> are the reserves of gas estimated to be recoverable from the pool beyond the proved limits of the pool. The probable pool limits are based on normal geological expectation.

<u>Established Reserves</u> are the reserves of gas whose existence and estimated amount can reasonably be counted upon. They include all of the proved reserves and a judgment portion (usually 50 per cent) of the probable reserves.

In its estimate of reserves, the Board has had regard for the estimates presented by the applicant and interveners at the hearing, the estimates included in various submissions presented recently to the Board, and evaluations made by its staff. The staff has reviewed all estimates submitted by the applicant and the interveners as well as its own previous estimates where desirable because of production history, additional drilling, or other new data.

The majority of the increases in the Board's estimates of remaining marketable reserves in the five-month period ending May 31, 1969, were the result of successful development drilling in various pools, and the majority of the reductions were due

to the production of gas during the period.

A comparison of the Board's reserve estimates for the year ending December 31, 1968, and at May 31, 1969, follows:

	Actual Basis	1,000 Btu Basis
	(Trillions	of Cubic Feet)
Remaining Established Reserves of Marketable gas at December 31, 1968	43.4	45.8
Net Additions to Reserves	1.4	1.5
Marketable Gas Produced	0.5	0.5
Remaining Established Reserves of Marketable Gas at May 31, 1969	44.3	46.8

The following tabulation lists some of the larger pools or strata for which there have been significant changes in the Board's estimates of initial marketable reserves (unadjusted for heating value) or for which there are significant differences between the Board's estimate and the reserve estimates of other interested parties:

Field or Area Pool or Stratum	Board's Estimate as of Dec. 31 1968	Board's Estimate as of May 31 1969	Other Estimates as of May 31, 1969 Estimators	Other Estimates as of May 31, 1969 Estimates
Brazeau River Elkton A	450	480	Trans-Canada	460
Brazeau River Elkton B	140	180	Trans-Canada	244
Greencourt Pekisko A	62	85	Trans-Canada	83
Harmattan East Rundle	900	800	None	
Kaybob South Beaverhill Lake A	1,800	2,100	Consolidated	2,616
			Trans-Canada	2,308
Obed D-2A	60	125	Trans-Canada	117
Provost Viking A and Viking B	900	900	Trans-Canada	1,001
Quirk Creek Rundle A	420	500	Consolidated	540
			Trans-Canada	438
Ricinus Leduc 19-35-8	Nil	80	Consolidated	140
			Pacific	154
			Trans-Canada	163
Strachan D-3A	700	1,400	Consolidated	1,550
			Gulf/Amerada	1,593
			Trans-Canada	1,418
Waskahigan Dunvegan A	47	90	None	-
Westerose South D-3A	1,250	1,350	Trans-Canada	1,365

Brazeau River Elkton A Pool: The Board's estimate of initial marketable reserves in the Brazeau River Elkton A Pool has been increased by 40 Bcf since December 31, 1968, due to information from one new well and a re-evaluation of the reservoir volume.

Brazeau River Elkton B Pool: This pool was re-evaluated after the addition of one well, and the reserves have been increased by 40 Bcf. The Trans-Canada estimate is substantially larger than that of the Board. The difference between these estimates is due largely to a variance in opinion concerning the shape and thus the volume of the reservoir.

Greencourt Pekisko A Pool; The addition of two wells on the east side of this pool has resulted in an increase in reserves from 62 to 85 Bcf.

Harmattan East Rundle Pool: The associated gas reserves in the Harmattan East Rundle Pool have been decreased by 100 Bcf despite modest enlargement of the pool in two areas. The decrease results from a re-evaluation of the gas interval porosity and water saturation, and from detection of a significant error in a previous calculation of the reservoir volume.

Kaybob South Beaverhill Lake A Pool: In its decision on an application by Chevron Standard Limited regarding gas cycling in this pool, the Board established the pool reserves to be 2,000 Bcf, effective May 1, 1969. In light of the evidence now before it, the Board has increased its reserve estimate to 2,100 Bcf. The increase in reserves since December 31, 1968, is attributable to an increase in estimated rock volume resulting from development drilling. The reserve estimate of Trans-Canada is larger than that of the Board because of differences in estimates of fluid saturation and recovery. The Consolidated

estimate differs from the Board's estimate in the same factors and also with respect to the estimated reservoir volume.

<u>Obed D-2A Pool:</u> One new D-2 well was added at Obed since the previous reserves estimate and with the information from the three wells a single pool isopach was prepared. The additional data thus led to the doubling of the D-2 reserves in the field.

<u>Provost Viking A and Viking B Pools:</u> The aggregate reserve estimate for these pools remains unchanged at 900 Bcf. The Board and Trans-Canada have both used material balance calculations to estimate reserves, but the resulting reserve estimates are significantly different. This difference is unlikely to be reconciled until additional pressure data are available.

<u>Quirk Creek Rundle A Pool:</u> The Board's evaluation of new data from this pool resulted in higher estimates of porosity and gas saturation, and increased the estimated reserves to 500 Bcf. The principal differences between the estimates of the Board, Consolidated and Trans-Canada are in recovery and reservoir volume.

<u>Ricinus Leduc 19-35-8:</u> The reserves of this new single well reservoir have been established by the Board at 80 Bcf. The difference between the estimates of the Board and others results principally from difference in the area assigned to the pool.

<u>Strachan D-3A Pool:</u> Development drilling in this high-relief

reservoir has resulted in a doubling of the reserves to 1,400 Bcf since the 1968 year-end. The main differences amongst the various reserves estimates are in the pore volume and recovery estimates.

Waskahigan Dunvegan A Pool: A reassessment of the extent of this pool resulted in the inclusion in the isopach of three wells for which individual reserves assignments were made in the past. The Board's estimate of the reserves is now 89 Bcf, some 42 Bcf greater than the previous total of the reserves of the main pool and the three wells.

Westerose South D-3A Pool: A new development well in the southern part of this pool encountered an unexpectedly large thickness of gas pay, increasing the pool average pay thickness by more than 15 per cent. Partially offsetting this is an increase in the Board's estimate of reservoir loss. The net effect of these changes on the pool reserves is an increase of 100 Bcf to 1350 Bcf.

The Board's estimates of established reserves of gas tabulated by fields and areas are presented in Table A-1. Within each field or area, pools designated by Board orders and having initial marketable reserves of 10 billion cubic feet or greater are shown separately. The reserves of the remaining pools in a field or area are grouped by formation. The table does not show separately fields or areas where the Board's estimate of initial marketable reserves is less than 10 billion cubic feet unless the reserve is supplying a market. In addition, the table does not show reserves by field, area or formation where the data

used in calculating the reserves are confidential. In exception to this rule, the reserves of four confidential pools at Bassano, Obed, Ricinus and Whiskey which were considered at the hearing are included in Table A-1, but detailed reservoir data are not tabulated for these pools.

The sum of the reserves in non-producing fields or areas having an initial marketable reserve of less than 10 billion cubic feet, and the sum of the reserves in confidential fields, pools, or areas are shown at the end of the table. These reserves are included in the provincial total.

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ACHESON									
VIKING	5	0.75	0.05	4	2	2	1020	2	
BLAIRMORE	5	0.80	0.05	4	1	3	1040	3	
BLAIRMORE ASSOC	27	0.85	0.10	20**					
BLAIRMORE SOLN	7	0.65	0.55	2**	5**	17	1050	18	
D-3 A SOLN	76	0.70	0.55	26	7	19	1070*	20	
ACHESON EAST									
BLAIRMORE	2	0.85	0.10	2		2	1050	2	
BLAIRMORE SOLN	10	0.65	0.45	4		4	1050	4	
ADEN									
BOW ISLAND	5	0.85	0.05	4		4	1000	4	
BASAL COLORADO	7	0.85	0.05	6	2	4	1000	4	
BLAIRMORE	1	0.75	0.05	1		1	1020	1	
SUNBURST-SWIFT	2	0.90	0.05	2	1	1	1040	1	
MISSISSIPPIAN	13	0.90	0.10	10	8	2	1040	2	
ALDERSON									
MILK RIVER A	46	0.50	0.05	22	5	17	960	16	6460
MILK RIVER (OTHER)	5	0.70	0.05	3	1	2	960	2	
2WS A	500	0.70	0.05	330	12	318	960	305	321500
BOW ISLAND	25	0.80	0.05	20		20	1000	20	
BASAL COLORADO	13	0.85	0.05	10		10	1030	10	
ALEXANDER									
BASAL QUARTZ A	140	0.85	0.03	120	110	10	1060*	11	
MANNVILLE (OTHER)	6	0.40	0.05	2	2	¤ 1	1060*	¤ 1	
ALEXIS									
MANNVILLE	8	0.85	0.05	7		7	1040	7	
BANFF	11	0.85	0.15	9		9	1060	10	
ALIX									
BLAIRMORE	10	0.90	0.05	8		8	1090*	9	
D-2 ASSOC	5	0.85	0.35	3		3	1130*	3	
D-2 SOLN	6	0.65	0.65	1		1	1130*	1	
AMBER									
SLAVE POINT	3	0.90	0.15	2		2	1100*	2	
SULPHUR POINT	2	0.90	0.20	1		1	1100*	1	
MUSKEG	6	0.90	0.25	4		4	1120*	4	
KEG RIVER ASSOC	12	0.90	0.10	8		8	1200*	10	
ANTE CREEK									
PEACE RIVER	11	0.85	0.05	8		8	1100	9	
GETHING 36-67-24	13	0.85	0.05	11		11	1100	12	500
GETHING	13	0.85	0.05	10		10	1100	11	
TRIASSIC	5	0.85	0.05	4		4	1140	5	
ANTELOPE									
VIKING A	13	0.80	0.05	10	1	9	1020	9	4620
BANFF	17	0.80	0.05	13	5	8	1020	8	
ATHABASCA									
GRAND RAPIDS	6	0.85	0.05	5	2	3	1000	3	
WABAMUN	4	0.90	0.05	3		3	980	3	
ATHABASCA EAST									
MANNVILLE	1	0.80	0.05	1		1	1090	1	

¤ MEANS LESS THAN
* MEASURED HIGHER HEATING VALUE

** INCLUDES ASSOCIATED GAS PRODUCTION
*** DEFINITIONS OF COLUMN HEADINGS APPEAR IN APPENDIX 1

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1966 NUL	2
									1967 NUL	3
									1967 NUL	4
									1966 NUL	5
										6
							5080	1950	1966 NUL	7
										8
										9
									1967	10
									1968 NUL	11
										12
										13
									1968 CMG	14
									1968 CMG	15
									1966	16
									1968 CMG	17
										18
									1961 CMG	19
										20
										21
52	0.20	0.50	420	55	0.94	0.58	970	1941	1968 LOCAL UTILITY	22
									1968 LOCAL UTILITY	23
5	0.20	0.40	830	80	0.90	0.58	1970	1956	1967 TCPL	24
									1964 TCPL	25
										26
									1965 LOCAL UTILITY	27
										28
										29
		GIP BASED ON MATERIAL BALANCE					3830	1954	1967 NORTH CANADIAN OILS	30
									AND CALGARY POWER	31
									1961	32
										33
										34
									1968	35
									1968	36
										37
										38
									1962	39
									1969	40
									1968	41
										42
										43
									1968 CONSIDERED BEYOND	44
									1968 ECONOMIC REACH	45
									1968	46
									1968	47
										48
										49
									1964	50
35	0.15	0.30	2200	125	0.83	0.62	5670	1961	1967	51
									1967	52
									1967	53
										54
										55
8	0.22	0.50	950	80	0.88	0.59	2360	1957	1967 TCPL	56
									1967 TCPL	57
										58
										59
									1957 LOCAL UTILITY	60
									1957	61
										62
										63
									1957	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ATHABASCA EAST (CONTINUED)									
D-1	4	0.60	0.05	2	1	1	1000	1	
ATIM									
VIKING	2	0.80	0.05	1		1	1000	1	
MANNVILLE	2	0.85	0.05	2	1	1	1070*	1	
ATLEE-BUFFALO									
VIKING A	61	0.75	0.05	43	12	31	970	30	31910
VIKING B	29	0.75	0.05	21	1	20	970	19	17310
VIKING (OTHER)	4	0.75	0.05	3		3	970	3	
BASAL COLORADO	6	0.80	0.05	5		5	1020	5	
BASAL MANNVILLE A	29	0.80	0.05	22		22	960	21	9550
BASAL MANNVILLE B	17	0.80	0.05	13		13	960	12	4990
MANNVILLE (OTHER)	6	0.85	0.05	5		5	960	5	
BANTRY									
MILK RIVER A	46	0.80	0.05	35	1	34	960	33	18400
2WS	1	0.80	0.05	1		1	970	1	
VIKING	25	0.80	0.05	19		19	970	18	
BASAL COLORADO	3	0.80	0.05	3	1	2	970	2	
MANNVILLE	12	0.85	0.05	9		9	1030	9	
MANNVILLE A ASSOC	27	0.85	0.10	21		21	1060*	22	5040
MANN ASSOC (OTHER)	26	0.85	0.05	21		21	1060*	22	
MANNVILLE A SOLN	50	0.70	0.35	23		23	1060*	24	
BAPTISTE									
MANNVILLE	6	0.80	0.05	5		5	970	5	
WABAMUN A	15	0.80	0.05	11		11	980	11	3840
BASHAW									
VIKING	1	0.75	0.05	1		1	970	1	
MANNVILLE	13	0.90	0.05	11		11	1000	11	
MANNVILLE ASSOC	12	0.80	0.05	9		9	1030*	9	
D-3 A ASSOC	16	0.80	0.15	11		11	1100*	12	2740
D-3 ASSOC (OTHER)	2	0.80	0.15	1		1	1100*	1	
BASSANO									
BOW ISLAND	2	0.85	0.05	2		2	1010*	2	
BASAL COLORADO	6	0.80	0.05	5		5	1010*	5	
MANNVILLE C	15	0.85	0.05	12		12	1020*	12	
MANNVILLE	8	0.85	0.05	7		7	1020*	7	
BEAVER CROSSING									
COLONY	1	0.70	0.05	1		1	1000	1	
BHL LK-FT SASK									
VIKING (MAIN)	610	0.85	0.05	490	143	347	1010	350	
VIKING (OTHER)	37	0.85	0.05	30		30	1010	30	
MANNVILLE	4	0.85	0.05	3		3	1010	3	
BELLIS									
MANNVILLE	7	0.75	0.05	5		5	1015	5	
NISKU A	43	0.85	0.05	35		35	1000	35	14750
NISKU (OTHER)	1	0.70	0.05	1		1	1000	1	
BELLOY									
NOTIKEWIN	9	0.80	0.05	7		7	980	7	
GETHING A	32	0.80	0.05	24		24	980	24	12350
GETHING B	31	0.90	0.05	27		27	980	26	6170
DEBOLT A	23	0.90	0.05	20		20	1120	22	1100

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AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
11	12	13	14	15	16	17	18	19	20	
										1
									1968 LOCAL UTILITY	2
										3
										4
									1957	5
									1963 CIGOL	6
										7
										8
5	0.25	0.50	990	80	0.88	0.60	2600	1951	1967 TCPL	9
4	0.25	0.50	1010	80	0.87	0.60	2320	1954	1967 TCPL	10
									1967	11
									1967	12
										13
7	0.19	0.50	1410	90	0.85	0.59	3220	1953	1967 TCPL	14
8	0.19	0.50	1430	90	0.85	0.59	3290	1954	1967	15
									1968	16
										17
										18
15	0.15	0.35	400	55	0.94	0.57	960	1940	1961 LOCAL UTILITY	19
									1967	20
									1965	21
									1964 CWNG	22
										23
									1961	24
5	0.27	0.30	1560	85	0.79	0.73	3210	1948	1969	25
									1968	26
							3250	1948	1969	27
										28
										29
									1968 CONSIDERED BEYOND	30
23	0.15	0.30	510	70	0.93	0.57	1940	1959	1968 ECONOMIC REACH	31
										32
										33
									1963	34
									1966	35
									1966	36
17	0.05	0.15	2330	140	0.85	0.78	5760	1951	1966	37
										38
									1966	39
										40
										41
									1967	42
									1968	43
									1969	44
									1968	45
										46
										47
									1963 LOCAL UTILITY	48
										49
										50
		GIP BASED ON MATERIAL BALANCE					2590	1946	1966 NUL AND CIGOL	51
									1966	52
									1966	53
										54
										55
									1966	56
23	0.09	0.20	560	80	0.93	0.57	2100	1965	1966	57
									1966	58
										59
										60
									1961	61
8	0.14	0.40	1260	110	0.88	0.56	2990	1951	1961	62
14	0.14	0.40	1330	110	0.87	0.57	3100	1951	1961	63
39	0.10	0.20	1970	95	0.79	0.63	4700	1951	1961	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BENJAMIN CREEK									
RUNDLE 33-28-7	100	0.85	0.20	70		70	1070	75	2270
BERLAND RIVER									
LEDUC A	440	0.90	0.25	300		300	990	297	1100
BERLAND RIVER WEST									
WABAMUN 10-58-25	24	0.90	0.30	15		15	1020	15	1100
BERRY									
VIKING	1	0.85	0.05	1		1	1020	1	
MANNVILLE	8	0.85	0.05	7		7	1030	7	
BIG BEND									
WABISKAW 31-68-1	12	0.90	0.05	10		10	990	10	1100
MCMURRAY A	26	0.80	0.05	19		19	990	19	3920
MANNVILLE (OTHER)	33	0.75	0.05	24		24	990	24	
WABAMUN	20	0.80	0.05	15		15	1000	15	
BIGORAY									
PASKAPOO	2	0.60	0.05	1		1	1000	1	
BLAIRMORE	18	0.85	0.05	14		14	1080	15	
RUNDLE	20	0.85	0.10	15		15	1080	16	
BIGSTONE									
DUNVEGAN A	53	0.90	0.05	45		45	1140	51	6390
GETHING A	13	0.90	0.05	11		11	1070	12	1100
GETHING (OTHER)	11	0.90	0.05	9		9	1100	10	
WABAMUN	11	0.85	0.40	5		5	1050	5	
D-3 A	390	0.85	0.25	250	10	240	990*	238	7090
BINDLOSS									
VIKING A	420	0.75	0.05	300	118	182	980	178	57050
VIKING B	32	0.70	0.05	21	2	19	980	19	6110
VIKING (OTHER)	6	0.75	0.05	5		5	980	5	
BASAL MANNVILLE A	26	0.90	0.05	23		23	990	23	5310
BANFF	3	0.85	0.05	2		2	1000	2	
BITTERN LAKE									
VIKING	11	0.80	0.05	8		8	1020	8	
GLAUCONITIC A	38	0.85	0.05	30	7	23	1070	25	3530
GLAUCONITIC B	21	0.85	0.05	17	2	15	1070	16	1210
ELLERSLIE A	14	0.85	0.05	12		12	1070	13	2370
MANNVILLE	44	0.85	0.05	35		35	1070	37	
BLACK									
SLAVE POINT	18	0.90	0.15	13		13	1100	14	
SULPHUR POINT ASSOC	1	0.85	0.15	1		1	1100	1	
MUSKEG	1	0.85	0.10	1		1	1100	1	
KEG RIVER	5	0.85	0.15	3		3	1150	3	
KEG RIVER ASSOC	4	0.85	0.15	3		3	1200	4	
BLACK BUTTE									
2WS	2	0.80	0.05	2		2	960	2	
BOW ISLAND A	21	0.85	0.05	17	3	14	980	14	3300
BASAL COLORADO A	15	0.85	0.05	12	4	8	1000	8	2840
BSL COLORADO (OTHER)	10	0.85	0.05	8	5	3	1000	3	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
112	0.05	0.20	3910	230	0.93	0.68	10600	1961	1966
562	0.08	0.20	5340	250	1.00	0.70	12290	1958	1959
71	0.04	0.20	4800	260	0.98	0.70	12320	1958	1959 CONSIDERED BEYOND
									ECONOMIC REACH
									1969 TCPL
									1967 TCPL
29	0.20	0.30	800	80	0.86	0.59	2430	1957	1957
17	0.20	0.35	900	85	0.88	0.60	2710	1953	1965
									1968
									1968
									1959
									1960
									1959
12	0.15	0.45	2600	145	0.79	0.69	6440	1959	1966
20	0.14	0.30	2500	215	0.89	0.66	7780	1960	1961
									1961
									1964
86	0.07	0.15	4800	240	0.97	0.69	11080	1960	1964 TCPL
14	0.29	0.45	990	80	0.88	0.59	2260	1952	1967 TCPL
10	0.29	0.45	1000	80	0.88	0.59	2530	1957	1967 TCPL
									1967
7	0.23	0.40	1460	85	0.85	0.59	2770	1954	1967
									1967
									1967
17	0.25	0.40	1310	115	0.86	0.64	4010	1956	1967 CIGOL, PLAINS WEST
29	0.24	0.40	1370	115	0.85	0.64	4180	1947	1967 ERN GAS & ELEC AND
									NUL
11	0.19	0.35	1350	115	0.83	0.68	4140	1952	1967
									1967 CIGOL
									1967 CONSIDERED BEYOND
									1967 ECONOMIC REACH
									1967
									1967
									1967
									1961
25	0.20	0.35	660	75	0.92	0.56	2200	1944	1963 CMG
15	0.20	0.40	930	80	0.89	0.58	2540	1944	1968 CMG
									1968 CMG

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BLACK BUTTE (CONTINUED)									
SUNBURST-SWIFT A	18	0.90	0.05	15	9	6	1000	6	2040
SAWTOOTH A	28	0.80	0.05	21	17	4	1000	4	
MANNVILLE (OTHER)	7	0.85	0.05	5		5	1030	5	
RUNDLE A	16	0.80	0.05	12	5	7	1020	7	2750
BLACK DIAMOND									
RUNDLE A	24	0.85	0.15	17		17	1100	19	500
BLUERIDGE									
MANNVILLE	3	0.80	0.05	2		2	1100	2	
JURASSIC A	14	0.90	0.05	12		12	1100	13	500
JURASSIC (OTHER)	8	0.80	0.10	5		5	1100	6	
PEKISKO	2	0.75	0.05	2		2	1130	2	
PEKISKO ASSOC	7	0.80	0.10	5		5	1130	6	
BOLLOQUE LAKE									
VIKING	2	0.80	0.05	1		1	1060	1	
MANNVILLE	14	0.80	0.05	10		10	990	10	
BONNIE GLEN									
CARDIUM SOLN	2	0.65	0.10	1		1	1040*	1	
VIKING	2	0.85	0.10	1		1	1050	1	
MANNVILLE	5	0.85	0.10	4	3	1	1100*	1	
WABAMUN	1	0.85	0.10	1		1	1100*	1	
GRAMINIA	1	0.85	0.10	1		1	1100*	1	
D-3	14	0.70	0.15	9	7	2	1100*	2	
D-3 A ASSOC	430	0.85	0.15	310		310	1220*	378	2990
D-3 A SOLN	540	0.70	0.25	280	56	224	1220*	273	
BONNYVILLE									
MANNVILLE	4	0.80	0.05	3	3	□ 1	980	□ 1	
MANNVILLE ASSOC	1	0.80	0.05	1		1	980	1	
BOUNDARY LAKE SOUTH									
CADOMIN	11	0.80	0.10	8		8	1060	8	
TRIASSIC	4	0.85	0.10	4	1	3	1050	3	
KISKATINAW D	37	0.85	0.05	29	11	18	1080	19	
KISKATINAW E	19	0.85	0.10	15		15	1080	16	1100
KISKATINAW (OTHER)	4	0.85	0.05	3	2	1	1080	1	
GOLATA A	13	0.85	0.05	11	8	3	1080	3	1000
GOLATA B	16	0.85	0.05	13	7	6	1080	6	1000
BOW ISLAND									
BOW ISLAND	48	0.90	0.05	40	14	26	1030	27	
BOYLE									
MANNVILLE	6	0.80	0.05	5		5	1000	5	
DETRITAL	2	0.85	0.05	1		1	1000	1	
NISKU	9	0.85	0.05	8		8	990	8	
BRAEBURN									
CADOMIN	4	0.80	0.05	3	1	2	1060*	2	
BALDONNEL A	29	0.80	0.10	21	5	16	1090*	17	4890
BELLOY A	55	0.80	0.05	42	3	39	1030*	40	3560
BRAZEAU RIVER									
ELKTON A	670	0.80	0.10	480		480	1050*	504	41180
ELKTON B	250	0.80	0.10	180		180	1040*	187	16230
SHUNDA A	110	0.75	0.10	74		74	1080*	80	24370

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
19	0.20	0.30	1030	85	0.87	0.57	2960	1944	1963 CMG	2
		GIP BASED ON MATERIAL BALANCE					3200	1944	1967 CMG	3
									1963 CMG	4
18	0.10	0.20	1200	90	0.87	0.58	3280	1944	1968 CMG	5
										6
										7
59	0.10	0.15	3630	195	0.87	0.74	9020	1967	1967	8
										9
										10
									1964	11
26	0.28	0.30	1800	150	0.85	0.66	5500	1957	1966	12
									1968	13
									1968	14
										15
									1969	16
										17
										18
									1966	19
									1967	20
										21
										22
									1965	23
									1963	24
									1964 NUL	25
									1967	26
										27
									1967	28
									1967 NUL	29
216	0.09	0.10	2440	140	0.79	0.70	6700	1952	1966	30
							7000	1952	1966 NUL	31
										32
										33
									1964 LOCAL UTILITY	34
									1963	35
										36
										37
									1964	38
									1968	39
		GIP BASED ON MATERIAL BALANCE					6210	1964	1969 WESTCOAST	40
22	0.13	0.10	2360	145	0.86	0.60	6130	1965	1969 WESTCOAST	41
										42
									1966 WESTCOAST	43
17	0.14	0.20	2370	145	0.86	0.59	6100	1958	1969 WESTCOAST	44
20	0.14	0.20	2370	145	0.86	0.59	6100	1964	1969 WESTCOAST	45
										46
										47
	RESERVE BASED ON PRODUCTION & INJECTION DATA						1920	1909	1953 CWNG STORAGE	48
									RESERVOIR	49
										50
										51
									1966	52
									1966	53
									1966	54
										55
										56
									1966 WESTCOAST	57
8	0.16	0.30	2150	145	0.86	0.61	5680	1954	1968 WESTCOAST	58
35	0.11	0.50	2970	180	0.90	0.58	7280	1954	1968 WESTCOAST	59
										60
										61
17	0.11	0.10	3860	215	0.94	0.64	10150	1959	1969	62
19	0.11	0.20	3870	230	0.95	0.68	9870	1965	1969	63
9	0.08	0.30	3910	205	0.94	0.65	10200	1965	1968	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BROOKS									
MILK RIVER	9	0.80	0.05	7	4	3	990	3	
BROWN CREEK									
RUNDLE 20-44-17	59	0.80	0.15	40		40	970	39	2000
BRUCE									
VIKING	25	0.80	0.05	19		19	1000	19	
MANNVILLE	9	0.80	0.05	7		7	1020	7	
BURNT TIMBER									
RUNDLE A	370	0.85	0.20	250		250	1030	258	12160
CALAIS									
GETHING	14	0.85	0.05	11		11	1000	11	
CADOMIN	12	0.85	0.05	10		10	1000	10	
CALLING LAKE									
MANNVILLE	2	0.85	0.05	2		2	1000	2	
D-2 A	49	0.75	0.05	35		35	1000	35	24810
CAMPBELL-NAMAO									
BLAIRMORE	4	0.85	0.05	3		3	1020	3	
BLAIRMORE E ASSOC	31	0.80	0.05	23**					1740
BLAIR ASSOC (OTHER)	11	0.80	0.05	8**					
BLAIRMORE SOLN	8	0.60	0.05	4**	20**	15	1020*	15	
CARBON									
BASAL COLORADO	4	0.85	0.05	3		3	1020	3	
GLAUCONITIC	160	0.85	0.05	130	29	101	1120	113	11800
MANNVILLE (OTHER)	4	0.85	0.05	3		3	1100	3	
RUNDLE	4	0.85	0.05	3		3	1110	3	
CAROLINE									
VIKING	2	0.80	0.05	1		1	1040*	1	
VIKING A ASSOC	160	0.80	0.05	120	5	115	1040*	120	40600
BASAL MANNVILLE B	15	0.85	0.10	12	1	11	1070	12	500
BASAL MANNVILLE C	16	0.85	0.10	12		12	1070	13	500
MANNVILLE (OTHER)	17	0.85	0.05	13		13	1040*	14	
ELKTON D	14	0.85	0.10	11		11	1020*	11	500
ELKTON (OTHER)	12	0.85	0.15	9		9	1020*	9	
CARSON CREEK									
BEAVERHILL LAKE A	210	0.85	0.15	150	10	140	1080*	151	15840
BEAVERHILL LAKE B	110	0.85	0.15	80	-16	96	1080*	104	6980
CARSON CREEK NORTH									
BHL LK A ASSOC	26	0.85	0.15	19		19	1100*	21	2880
BHL LK ASSOC (OTHER)	7	0.85	0.15	5		5	1100*	6	
BHL LK A SOLN	110	0.45	0.20	38	4	34	1100*	37	
BHL LK B SOLN	330	0.40	0.20	110	9	101	1100*	111	
CARSTAIRS									
BLAIRMORE	16	0.85	0.15	11		11	1100	12	
ELKTON A	1140	0.90	0.15	870	261	609	1070*	652	
ELKTON ASSOC	6	0.85	0.15	5		5	1070*	5	
CASTOR									
VIKING A	33	0.80	0.05	25		25	1040	26	20320

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1961 LOCAL UTILITY
89	0.04	0.20	4550	115	0.98	0.64	10840	1960	1964 CONSIDERED BEYOND ECONOMIC REACH
									1967
									1967
61	0.06	0.15	3800	105	0.91	0.72	10900	1959	1966
									1960 LOCAL UTILITY
									1964
									1967 GREAT CANADIAN OIL SANDS LIMITED
25	0.13	0.45	360	70	0.95	0.56	1550	1964	1967 GREAT CANADIAN OIL SANDS LIMITED
									1964
30	0.19	0.20	1220	115	0.85	0.67	3620	1951	1969 CIGOL
									1969 CIGOL
									1964 CIGOL
									1964
22	0.20	0.35	1480	120	0.83	0.68	4750	1955	1966 CWNG
									1964
									1965
									1967
7	0.11	0.25	2500	165	0.83	0.67	8070	1957	1967 TCPL
26	0.15	0.30	4260	185	0.92	0.78	9460	1958	1964 A&S
27	0.15	0.30	4040	180	0.89	0.78	8900	1964	1965
									1965 TCPL
29	0.12	0.20	3600	195	0.86	0.83	9170	1960	1965 A&S
									1965 A&S
20	0.08	0.20	3790	200	0.85	0.97	8550	1961	1964 POOLS BEING CYCLED
24	0.08	0.20	3790	200	0.85	0.97	8610	1957	1964 AND GAS SOLD TO NUL AND A&S
10	0.09	0.90	3740	185	0.84	0.79	8580	1958	1969
							8700	1958	1969
							8630	1959	1965 INJ INTO CARSON CRK
							8740	1958	1965 INJ INTO CARSON CRK
									1967
		GIP BASED ON MATERIAL BALANCE					8100	1958	1967 TCPL
									1967
6	0.21	0.55	860	90	0.89	0.61	3160	1949	1969

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
CASTOR (CONTINUED)									
MANNVILLE	4	0.85	0.05	3		3	1090	3	
CESSFORD									
VIKING H	16	0.75	0.03	11		11	1020*	11	6460
VIKING I	14	0.75	0.03	10		10	1020*	10	1100
VIKING (OTHER)	78	0.65	0.03	49	8	41	1060*	43	
BASAL COLORADO E	120	0.80	0.04	90	41	49	1030*	50	24430
BSL COLORADO (OTHER)	55	0.65	0.04	34	5	29	1030*	30	
BSL COLO A ASSOC	890	0.85	0.04	730	339	391	1030*	403	135000
BSL COLORADO A SOLN	20	0.65	0.21	10		10	1030*	10	
GLAUCONITIC A	19	0.75	0.05	13		13	1080*	14	8410
GLAUCONITIC B	15	0.75	0.05	11	1	10	1080*	11	5810
MANNVILLE A	59	0.80	0.04	45	15	30	1000*	30	13580
MANNVILLE F	23	0.85	0.04	19	3	16	1000*	16	3670
MANNVILLE G	40	0.85	0.04	33	21	12	1000*	12	5760
MANNVILLE H	71	0.85	0.04	58	24	34	1000*	34	7010
MANNVILLE I	22	0.75	0.04	16	5	11	1000*	11	5470
MANNVILLE J	32	0.85	0.04	26	14	12	1000*	12	4870
MANNVILLE K	17	0.75	0.04	12	1	11	1000*	11	3300
MANNVILLE (OTHER)	61	0.85	0.04	49	16	33	1030*	34	
MANNVILLE C ASSOC	19	0.85	0.04	16		16	1030*	16	3930
MANN ASSOC (OTHER)	2	0.85	0.04	1		1	1030*	1	
MANNVILLE SOLN	12	0.65	0.17	7	4	3	1030*	3	
CHAMBERS									
BLAIRMORE	6	0.85	0.10	4		4	1030	4	
ELKTON	13	0.85	0.15	9		9	1080	10	
CHARLOTTE LAKE									
MANNVILLE	3	0.75	0.05	2		2	1000	2	
CHESTERMERE									
RUNDLE A	35	0.85	0.15	25		25	1100	28	1100
CHIGWELL									
MANNVILLE A	46	0.85	0.10	35	13	22	1110	24	
MANNVILLE (OTHER)	13	0.75	0.10	9	1	8	1110	9	
CHINOOK RIDGE									
PADDY	13	0.80	0.10	9		9	1020	9	
CADOTTE 12-65-13	32	0.80	0.10	23		23	1020	23	1100
NOTIKEWIN 12-65-13	20	0.80	0.10	15		15	1020	15	500
CLIVE									
VIKING	4	0.80	0.05	3		3	990	3	
MANNVILLE	5	0.85	0.05	4		4	1020	4	
D-2 A ASSOC	39	0.85	0.30	23		23	1050*	24	4240
D-2 ASSOC (OTHER)	1	0.85	0.30	1		1	1050*	1	
D-2 SOLN	38	0.40	0.55	7		7	1050*	7	
D-3 A ASSOC	33	0.75	0.30	18		18	1050*	19	3950
D-3 A SOLN	70	0.40	0.60	11		11	1050*	12	
COLD LAKE									
MANNVILLE	8	0.70	0.05	6	4	2	1000	2	
COMREY									
2WS	5	0.80	0.05	4		4	940	4	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
									1963 LOCAL UTILITY	2
6	0.21	0.45	1110	75	0.86	0.59	2630	1953	1968	5
15	0.21	0.45	1100	80	0.86	0.59	2730	1953	1968	6
									1968 TCPL	7
8	0.24	0.40	1260	85	0.84	0.61	2970	1950	1968 TCPL	8
									1968 TCPL	10
10	0.27	0.40	1260	80	0.84	0.61	2860	1950	1968 TCPL	11
							2870	1950	1968	12
6	0.17	0.50	1370	100	0.82	0.65	3850	1960	1968 TCPL	13
6	0.17	0.50	1370	95	0.82	0.65	3570	1962	1968	14
13	0.16	0.55	1410	100	0.82	0.66	3870	1959	1968 TCPL	16
10	0.24	0.45	1420	90	0.81	0.65	3290	1951	1968 TCPL	17
13	0.21	0.50	1420	90	0.81	0.65	3390	1950	1968 TCPL	18
14	0.25	0.45	1440	85	0.80	0.65	3070	1954	1968 TCPL	19
7	0.27	0.50	1420	90	0.81	0.65	3340	1951	1968 TCPL	20
10	0.23	0.45	1540	90	0.80	0.65	3400	1958	1968 TCPL	22
8	0.27	0.50	1420	90	0.81	0.65	3255	1952	1968 TCPL	23
									1968 TCPL	24
6	0.24	0.35	1400	90	0.81	0.65	3320	1951	1968 TCPL	25
									1968	26
									1968	28
									1967	31
									1967	32
									1967 CANADIAN FORCES BASE	35
									AT COLD LAKE	36
42	0.10	0.15	2790	155	0.80	0.76	6810	1968	1968	39
		GIP BASED ON MATERIAL BALANCE					5160	1952	1968 TCPL	42
									1968 TCPL	43
									1961 CONSIDERED BEYOND	46
23	0.20	0.30	3300	230	0.85	0.80	9200	1956	1961 ECONOMIC REACH	47
32	0.20	0.30	3400	235	0.86	0.80	9460	1956	1961	48
									1966	51
									1966	52
20	0.06	0.15	2480	150	0.73	0.75	6040	1951	1967	53
									1968	54
									1968	56
20	0.06	0.15	2550	150	0.73	0.81	6140	1952	1967	57
							6150	1952	1968	58
									1966 LOCAL UTILITY	61
									1960	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
COMREY (CONTINUED)									
BOW ISLAND	34	0.75	0.05	24	17	7	940	7	6980
BOW ISLAND (OTHER)	1	0.80	0.05	1		1	940	1	
UPPER MANNVILLE A	16	0.90	0.05	14		14	1000	14	1100
SAWTOOTH	1	0.80	0.05	1		1	1000	1	
CONNORSVILLE									
VIKING	8	0.80	0.05	6	2	4	1000	4	
LOWER MANNVILLE A	52	0.85	0.05	42	3	39	1100	43	10110
MANNVILLE (OTHER)	10	0.85	0.05	8	1	7	1100	8	
COUNTESS									
BOW ISLAND A	34	0.80	0.05	26	5	21	1010*	21	14490
BOW ISLAND C	17	0.80	0.05	13	1	12	1010*	12	6080
BOW ISLAND F	15	0.85	0.05	12		12	1010*	12	2230
BOW ISLAND (OTHER)	29	0.80	0.05	22	1	21	1010*	21	
BASAL COLORADO A	170	0.85	0.05	140	76	64	1010*	65	
BSL COLORADO (OTHER)	6	0.90	0.05	5		5	1010*	5	
MANNVILLE	48	0.85	0.05	38	6	32	1020*	33	
BASAL QUARTZ B ASSOC	12	0.85	0.05	10		10	1020*	10	1370
MANN ASSOC (OTHER)	5	0.85	0.05	4		4	1020*	4	
MISS ASSOC	3	0.80	0.10	2		2	1030*	2	
CRAIGEND									
PELICAN	3	0.75	0.05	2		2	1000	2	
MANNVILLE	48	0.75	0.05	34		34	1000	34	
MANNVILLE ASSOC	3	0.75	0.05	2		2	1000	2	
GROSMONT A	210	0.75	0.05	150		150	1000	150	81000
CRAIG LAKE									
VIKING	1	0.75	0.05	1		1	1000	1	
CROSSFIELD									
CARDIUM SOLN	74	0.30	0.45	12	1	11	1140*	13	
BASAL QUARTZ A	81	0.85	0.10	62	2	60	1020*	61	12160
BASAL QUARTZ (OTHER)	36	0.85	0.10	28	1	27	1020*	28	
RUNDLE A	1230	0.90	0.10	1000	185	815	1070*	872	33600
RUNDLE B	900	0.85	0.15	650	214	436	1070*	467	21220
RUNDLE D	13	0.85	0.10	10		10	1020*	10	500
WABAMUN A	2080	0.85	0.50	890	106	784	980	768	102680
CROSSFIELD EAST									
BLAIRMORE	6	0.85	0.10	5		5	1020*	5	
ELKTON A	150	0.90	0.12	120	34	86	1140*	98	
ELKTON C	32	0.85	0.10	24		24	1140*	27	1100
WABAMUN A	1590	0.85	0.55	610	13	597	970	579	55510
DIXONVILLE									
MANNVILLE	9	0.85	0.05	7		7	980	7	
TRIASSIC	8	0.90	0.05	7		7	1030	7	
LEDUC	4	0.85	0.05	3		3	1070	3	
DONALDA									
VIKING B	25	0.80	0.05	19		19	970	18	9390
VIKING C	17	0.80	0.05	13		13	970	13	7170
VIKING (OTHER)	16	0.80	0.05	12		12	970	12	
MANNVILLE	11	0.85	0.05	9		9	980	9	
DOWLING LAKE									
MANNVILLE	5	0.80	0.05	3	2	1	1030*	1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
16	0.25	0.50	770	80	0.92	0.59	2480	1952	1968 CMG	2
									1960	3
33	0.21	0.35	990	80	0.88	0.57	2750	1968	1968 CMG	4
										5
									1960	6
										7
										8
									1964 TCPL	9
11	0.16	0.35	1410	105	0.85	0.61	3650	1956	1965 TCPL	10
									1965 TCPL	11
										12
										13
6	0.23	0.50	1040	85	0.87	0.60	2890	1951	1968 TCPL	14
7	0.22	0.50	1040	85	0.87	0.60	2860	1955	1968 TCPL	15
13	0.27	0.50	1170	85	0.86	0.60	2830	1967	1968	16
									1968 TCPL	17
										18
		GIP BASED ON MATERIAL BALANCE					3500	1951	1968 TCPL	19
									1968	20
									1964 TCPL	21
13	0.21	0.30	1470	110	0.82	0.67	4280	1958	1964	22
									1968	23
										24
									1961	25
										26
										27
									1967	28
									1968	29
									1967	30
31	0.12	0.55	410	75	0.94	0.58	1660	1961	1967	31
										32
										33
									1968 LOCAL UTILITY	34
										35
										36
							6670	1956	1966 TCPL	37
9	0.11	0.30	2890	150	0.82	0.70	7330	1957	1966 WESTCOAST AND TCPL	38
									1966 TCPL	39
39	0.12	0.15	3320	180	0.86	0.79	8410	1956	1964 A&S AND TCPL	40
										41
71	0.08	0.15	3040	165	0.88	0.70	7440	1957	1967 WESTCOAST AND TCPL	42
44	0.08	0.20	3310	180	0.88	0.71	8200	1951	1964	43
34	0.06	0.15	3630	165	0.71	0.90	8500	1954	1967 WESTCOAST AND TCPL	44
										45
										46
									1968	47
		GIP BASED ON MATERIAL BALANCE					7490	1960	1968 TCPL	48
48	0.09	0.20	2780	170	0.82	0.74	7590	1967	1968	49
51	0.05	0.20	3630	180	0.72	0.91	9000	1960	1968 TCPL	50
										51
										52
									1962 CONSIDERED BEYOND	53
									1962 ECONOMIC REACH	54
									1962	55
										56
										57
6	0.23	0.35	920	100	0.90	0.60	3280	1960	1969 CONSIDERED BEYOND	58
6	0.23	0.35	905	100	0.90	0.60	3420	1957	1969 ECONOMIC REACH	59
									1969	60
									1969	61
										62
										63
									1960 LOCAL UTILITY	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
DRUMHELLER									
VIKING	3	0.85	0.05	2		2	1080	2	
MANNVILLE F	27	0.85	0.05	21	1	20	1080	22	37440
MANNVILLE H	16	0.85	0.10	12	2	10	1080	11	2360
MANNVILLE (OTHER)	26	0.85	0.05	20		20	1080	22	
MANNVILLE ASSOC	12	0.80	0.05	9		9	1080	10	
PEKISKO	3	0.80	0.10	2		2	1080	2	
DUHAMEL									
VIKING	4	0.90	0.05	4		4	1000	4	
MANNVILLE	5	0.85	0.05	4		4	1030	4	
D-2 ASSOC	2	0.90	0.10	2		2	1100	2	
D-3 SOLN	6	0.50	0.55	1		1	1100	1	
DUNVEGAN									
CADOTTE	9	0.75	0.05	7		7	1010	7	
DEBOLT	3	0.90	0.05	3		3	1040	3	
DUVERNAY									
VIKING	4	0.80	0.05	3	2	1	1000*	1	
DYBERG									
BELLY RIVER	3	0.80	0.05	2		2	950	2	
VIKING	8	0.90	0.05	7		7	1000	7	
BSL QTZ 15-44-23	12	0.90	0.05	10		10	1020	10	1200
EAGLESHAM									
BLUESKY	5	0.85	0.05	4		4	1000	4	
CADOMIN ASSOC	7	0.85	0.05	5		5	1060	5	
DEBOLT A	17	0.85	0.05	14		14	1110	16	2040
DEBOLT B	19	0.85	0.05	15		15	1110	17	1100
DEBOLT C	26	0.85	0.05	21		21	1110	23	1100
EDSON									
GETHING A	210	0.85	0.10	160		160	1050	168	11310
ELKTON A	2340	0.90	0.10	1900	199	1701	1030*	1752	121500
ELKTON 26-51-19	22	0.85	0.10	17		17	1030*	18	1100
ELKTON (OTHER)	6	0.85	0.10	5		5	1030*	5	
SHUNDA	12	0.80	0.15	8		8	1030*	8	
EDWAND									
MANNVILLE	4	0.80	0.05	3		3	1000	3	
ELK POINT									
MANNVILLE	3	0.80	0.05	2	1	1	990*	1	
ELLERSLIE									
BLAIRMORE ASSOC	2	0.75	0.15	1		1	1000	1	
ENCHANT									
MILK RIVER	5	0.75	0.05	3		3	1000*	3	
BOW ISLAND A	15	0.75	0.05	11		11	1000*	11	28780
BOW ISLAND (OTHER)	16	0.85	0.05	12	3	9	1000*	9	
BASAL COLORADO	1	0.75	0.05	1		1	1000*	1	
UPPER MANNVILLE A	13	0.85	0.05	11	3	8	1000*	8	4010
MANNVILLE	10	0.85	0.10	8		8	1000*	8	
JURASSIC	2	0.75	0.10	2		2	1000*	2	
RUNDLE	5	0.85	0.10	4	2	2	1000*	2	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1967	2
9	0.20	0.25	1430	120	0.82	0.68	4220	1950	1968 TCPL	3
15	0.16	0.45	1450	125	0.84	0.66	4370	1961	1968 TCPL	4
									1966	5
										6
									1966	7
									1963 TCPL	8
										9
										10
									1965	11
									1965	12
									1957	13
									1966	14
										15
										16
									1963 CONSIDERED BEYOND	17
									1963 ECONOMIC REACH	18
										19
										20
									1961 WESTERN MINERALS AND	21
									LOCAL UTILITY	22
										23
										24
									1960 CONSIDERED BEYOND	25
									1960 ECONOMIC REACH	26
17	0.18	0.30	1480	130	0.84	0.62	4620	1954	1960	27
										28
										29
									1965	30
									1965	31
11	0.18	0.25	1870	135	0.85	0.64	4480	1952	1966	32
17	0.20	0.20	1980	125	0.83	0.64	4700	1959	1965	33
										34
23	0.20	0.20	2000	125	0.81	0.65	4700	1959	1965	35
										36
										37
27	0.10	0.25	3360	180	0.88	0.68	8400	1963	1968 TCPL	38
22	0.11	0.10	3880	225	0.94	0.63	9380	1962	1967 TCPL	39
31	0.08	0.10	3990	210	0.94	0.63	10120	1964	1966	40
									1966	41
										42
									1966 TCPL	43
										44
										45
									1966 LOCAL UTILITY	46
										47
										48
									1964 LOCAL UTILITY	49
										50
										51
									1966 EDMONTON LIQUID GAS	52
										53
										54
									1964	55
2	0.15	0.30	950	80	0.89	0.59	2470	1960	1967 TCPL	56
									1967 TCPL	57
									1962	58
										59
5	0.20	0.35	1580	90	0.81	0.66	3300	1953	1968 TCPL	60
									1961 TCPL	61
									1961	62
									1966 TCPL	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
EQUITY									
MANNVILLE	4	0.80	0.05	3		3	1130*	3	
LWR MANN A - PEK A	46	0.85	0.10	33	2	31	1130*	35	8720
ERSKINE									
VIKING	4	0.80	0.05	3		3	1040	3	
BLAIRMORE	21	0.80	0.10	15	4	11	1090	12	
D-2 SOLN	1	0.65	0.35	1		1	1100	1	
D-3	1	0.85	0.20	1		1	1070	1	
D-3 A ASSOC	29	0.90	0.20	21		21	1070	22	2510
D-3A SOLN	19	0.50	0.75	2		2	1110	2	
ESTHER									
BELLY RIVER A	21	0.75	0.05	15		15	990	15	31050
BANFF A	21	0.85	0.05	17	2	15	1000	15	1600
ETHEL LAKE									
MANNVILLE	3	0.80	0.05	2		2	1000	2	
ETZIKOM									
BOW ISLAND A	68	0.75	0.05	48	35	13	930	12	
MANNVILLE	2	0.75	0.05	1		1	1010	1	
EXCELSIOR									
VIKING	8	0.80	0.05	7	3	4	1000	4	
MANNVILLE A ASSOC	38	0.90	0.05	33		33	970	32	3270
EYREMORE									
BOW ISLAND	15	0.70	0.05	10		10	960	10	
FAIRYDELL-BON ACCORD									
VIKING A	110	0.80	0.05	88	35	53	1020	54	
VIKING (OTHER)	9	0.80	0.05	7	1	6	1020	6	
MANNVILLE	15	0.80	0.05	12	2	10	990	10	
MANNVILLE ASSOC	9	0.80	0.10	7		7	990	7	
FENN-BIG VALLEY									
VIKING	19	0.80	0.90	2	1	1	1000*	1	
D-2 A SOLN	150	0.65	0.85	15	7	8	1110*	9	
D-3 SOLN	9	0.60	0.85	1		1	1110*	1	
FERRIER									
CARDIUM	8	0.80	0.10	6		6	1000	6	
CARDIUM D ASSOC	74	0.80	0.10	53		53	1000	53	7710
CARDIUM E ASSOC	350	0.80	0.10	250		250	1000	250	13800
VIKING A SOLN	31	0.65	0.25	15	3	12	1130	14	
RUNDLE	2	0.80	0.10	2		2	1100	2	
BANFF	8	0.85	0.10	6		6	1100	7	
FIGURE LAKE									
VIKING	4	0.75	0.05	3		3	960	3	
MANNVILLE	13	0.80	0.05	10		10	1000	10	
D-2 B	13	0.85	0.05	11		11	1000	11	6700
D-2 (OTHER)	12	0.85	0.05	8		8	1000	8	
FLAT									
MANNVILLE	13	0.80	0.05	10		10	1020	10	
WABAMUN A	156	0.80	0.05	119		119	1040	124	32650

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
									1968 TCPL	2
21	0.08	0.35	1620	125	0.83	0.67	5420	1962	1967 TCPL	3
									1962	6
									1966 TCPL	7
									1969	8
									1968	9
33	0.06	0.20	2210	145	0.81	0.70	5300	1953	1966	11
									1966	12
3	0.31	0.35	330	55	0.95	0.58	800	1956	1964	15
26	0.19	0.30	1180	85	0.87	0.59	2770	1965	1966 TCPL	16
									1967 LOCAL EXPERIMENTAL	19
									PROJECT	20
		GIP BASED ON MATERIAL BALANCE					2230	1951	1967 SOUTH ALBERTA PIPE	23
									LINES	24
									1961	25
									1953 CIGOL AND PLAINS-	28
									WESTERN GAS & ELEC	29
24	0.20	0.35	1140	80	0.87	0.63	3450	1953	1953	30
									1955 CONSIDERED BEYOND	33
									ECONOMIC REACH	34
		GIP BASED ON MATERIAL BALANCE					2680	1950	1968 NUL	37
									1963 NUL	38
									1965 NUL	39
									1968	40
									1961 CWNG	43
							5290	1950	1966 CWNG	44
									1966	45
									1968	48
7	0.16	0.15	3170	160	0.83	0.71	6680	1965	1968	49
21	0.15	0.20	3140	150	0.80	0.77	6790	1965	1968	50
							8190	1955	1966 A&S	51
									1960	53
									1967	54
									1966	57
									1966	58
13	0.14	0.45	630	180	0.92	0.57	2260	1957	1966	59
									1966	60
									1968 LOCAL UTILITY	63
28	0.23	0.50	490	70	0.93	0.58	1870	1956	1968 TCPL	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
FOREMOST									
BOW ISLAND	31	0.85	0.05	27	8	19	950	18	10400
FORT KENT									
COLONY	6	0.75	0.05	4	2	2	980	2	
FOX CREEK									
VIKING A	97	0.75	0.05	69	1	68	1110	75	21790
NOTIKEWIN	7	0.80	0.05	5		5	1180	6	
CADOMIN	46	0.85	0.05	37		37	1160	43	
TRIASSIC	3	0.90	0.10	2		2	1160	2	
FOX CREEK WEST									
CADOMIN	15	0.85	0.05	12		12	1160	14	
GARRINGTON									
MANNVILLE	12	0.85	0.10	9		9	1010	9	
MANNVILLE ASSOC	3	0.90	0.15	2		2	1010	2	
RUNDLE	2	0.85	0.10	1		1	1020	1	
LEDUC 23-35-4	23	0.85	0.20	15		15	1020	15	500
LEDUC (OTHER)	7	0.85	0.20	5		5	1020	5	
LEDUC ASSOC 36-35-4	15	0.85	0.20	10		10	1020	10	500
GHOST PINE									
VIKING	9	0.80	0.05	7		7	1020	7	
UPPER MANNVILLE G&P	42	0.80	0.10	30	12	18	1030	19	11300
UPPER MANNVILLE Q	27	0.80	0.10	20		20	1030	21	2390
UPPER MANNVILLE U	28	0.80	0.10	20		20	1030	21	2850
LOWER MANNVILLE F	19	0.85	0.10	14	1	13	1030	13	1940
MANNVILLE (OTHER)	74	0.80	0.10	54	12	42	1030	43	
UPPER MANN W ASSOC	15	0.80	0.15	10		10	1050	11	5490
MANN ASSOC (OTHER)	23	0.75	0.15	15	1	14	1050	15	
PEKISKO B	17	0.80	0.10	12		12	1070	13	6520
RUNDLE (OTHER)	11	0.80	0.10	8	2	6	1070	6	
GILBY									
CARDIUM	2	0.85	0.10	2		2	1000	2	
VIKING ASSOC	4	0.80	0.05	3		3	1080*	3	
BASAL MANNVILLE D	33	0.80	0.15	22	5	17	1080*	18	2360
BASAL MANNVILLE H	62	0.80	0.10	44	3	41	1080*	44	5630
MANNVILLE (OTHER)	42	0.85	0.15	31		31	1080*	33	
MANNVILLE ASSOC	4	0.80	0.15	3		3	1080*	3	
BSL MANN A - JUR D	230	0.85	0.10	180	28	152	1080*	164	5860
JURASSIC A	75	0.80	0.04	58	4	54	1080*	58	6050
JURASSIC C	19	0.80	0.04	15	10	5	1080*	5	2010
JURASSIC E	86	0.80	0.04	66	3	63	1080*	68	7840
JURASSIC (OTHER)	8	0.80	0.05	6		6	1080*	6	
JURASSIC B ASSOC	18	0.75	0.04	13		13	1080*	14	1220
RUNDLE C	260	0.85	0.05	210	72	138	1080*	149	8070
RUNDLE D	150	0.85	0.05	120	37	83	1080*	90	11240
RUNDLE H	16	0.85	0.05	13		13	1080*	14	2420
RUNDLE (OTHER)	17	0.85	0.05	13		13	1080*	14	
WABAMUN	7	0.90	0.20	5		5	1170	6	
GLENEVIS									
MANNVILLE	16	0.80	0.10	12		12	1040	12	
GLEN PARK									
MANNVILLE	6	0.80	0.05	4		4	1140	5	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
7	0.24	0.20	690	70	0.92	0.58	2080	1916	1953 CWNG	2
										3
										4
									1966 LOCAL UTILITY	5
										6
										7
11	0.15	0.40	1480	140	0.85	0.67	5620	1957	1967	8
									1967	9
									1967	10
									1967	11
										12
										13
									1968	14
										15
										16
									1964	17
									1967	18
									1964	19
125	0.05	0.20	3760	220	0.94	0.75	10010	1954	1964	20
										21
									1964	22
85	0.05	0.20	3700	220	0.95	0.77	9880	1956	1964	23
										24
										25
									1967	26
6	0.20	0.35	1510	120	0.81	0.69	4580	1964	1967 TCPL	27
18	0.20	0.35	1520	125	0.81	0.67	4780	1955	1967 TCPL	28
14	0.20	0.35	1550	115	0.81	0.70	4640	1965	1967	29
										30
18	0.20	0.45	1550	125	0.82	0.68	4850	1955	1969 TCPL	31
									1967 TCPL	32
6	0.18	0.50	1520	110	0.75	0.76	4580	1963	1967 TCPL	33
									1967 TCPL	34
15	0.05	0.30	1620	125	0.82	0.69	5060	1962	1967	35
										36
									1967 TCPL	37
										38
										39
									1965	40
									1965	41
27	0.11	0.30	2250	160	0.83	0.70	6930	1962	1966 TCPL	42
20	0.12	0.35	2300	155	0.81	0.71	6880	1956	1965 TCPL	43
										44
									1966	45
									1967	46
53	0.14	0.30	2310	155	0.81	0.72	7130	1956	1967 TCPL	47
17	0.14	0.30	2300	150	0.81	0.73	6840	1953	1968 TCPL	48
13	0.15	0.30	2280	155	0.82	0.73	6920	1955	1968 TCPL	49
										50
18	0.13	0.35	2320	155	0.81	0.73	7030	1961	1968 TCPL	51
									1968	52
16	0.16	0.20	2310	160	0.82	0.73	6990	1958	1968	53
55	0.10	0.15	2290	160	0.82	0.73	6970	1955	1968 TCPL	54
32	0.07	0.20	2280	155	0.82	0.73	6770	1955	1968 TCPL	55
										56
29	0.04	0.20	2320	170	0.83	0.72	7210	1961	1968	57
									1968	58
									1961	59
										60
										61
									1966	62
										63
										64
									1965 NUL	65

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
GLEN PARK (CONTINUED)									
LEDUC SOLN	16	0.65	0.15	9	1	8	1250	10	
GOLD CREEK									
SPIRIT RIVER A	58	0.85	0.05	47		47	1050	49	3940
BLUESKY-GETHING A	63	0.85	0.10	48		48	1050	50	10230
GETHING	4	0.85	0.10	3		3	1050	3	
CADOMIN	11	0.80	0.15	9		9	1110*	10	
WABAMUN A	410	0.80	0.30	230		230	1040*	239	9400
WABAMUN B	92	0.80	0.30	51		51	1040*	53	1100
GOLDEN SPIKE									
VIKING	8	0.80	0.05	6	1	5	1050	5	
BLAIRMORE	14	0.80	0.05	11	1	10	1050	11	
D-1 A	25	0.90	0.10	20	12	8	1060	8	1260
D-2 ASSOC	3	0.85	0.15	3		3	1120	3	
D-2 SOLN	8	0.65	0.20	4	1	3	1120*	3	
D-3 A ASSOC		0.90	0.10		-51	51	1100*	56	
D-3 A SOLN	130	0.90	0.40	69	24	45	1130*	51	
GOODWIN									
MANNVILLE	1	0.75	0.10	1		1	1050	1	
JURASSIC A	20	0.85	0.10	15		15	1070	16	4560
GORDONDALE									
PEACE RIVER A	34	0.85	0.05	27	25	2	1000	2	9190
PEACE RIVER (OTHER)	1	0.85	0.05	1		1	1000	1	
GETHING A	39	0.85	0.05	29	22	7	1020	7	7850
GETHING (OTHER)	17	0.85	0.05	14	8	6	1020	6	
GREENCOURT									
JURASSIC A	39	0.80	0.10	28		28	1070	30	7800
JURASSIC B	14	0.80	0.05	10		10	1070	11	3770
PEKISKO	3	0.80	0.05	2		2	1130	2	
PEKISKO A ASSOC	110	0.85	0.10	85		85	1130	96	7110
HACKETT									
MANNVILLE A	60	0.90	0.10	49	9	40	1100	44	3420
MANNVILLE (OTHER)	2	0.90	0.10	1		1	1100	1	
HAIRY HILL									
VIKING	2	0.75	0.05	1		1	980	1	
COLONY A	22	0.90	0.05	19	13	6	1000*	6	3220
MANNVILLE (OTHER)	1	0.85	0.05	1		1	1000*	1	
NISKU	3	0.80	0.05	2		2	1000	2	
HALLIDAY									
VIKING	5	0.80	0.05	4	1	3	1040	3	
HAMELIN CREEK									
CADOTTE	3	0.80	0.05	2		2	1000	2	
GETHING	3	0.80	0.05	3		3	1010	3	
CADOMIN A	37	0.85	0.05	30	5	25	1060	27	
TRIASSIC	2	0.75	0.05	1		1	1160	1	
HANNA									
VIKING	10	0.85	0.05	8		8	1040	8	
MANNVILLE	3	0.85	0.05	2		2	1050	2	
BANFF	2	0.80	0.05	1		1	1080	1	
HARMATTAN EAST									
RUNDLE ASSOC	1060	0.85	0.11	800	-19	819	1080*	885	49300

OF ALBERTA, MAY 31,1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1966 NUL	2
										3
										4
24	0.15	0.15	1930	150	0.85	0.65	6470	1968	1968	5
6	0.12	0.20	3210	160	0.82	0.73	7110	1968	1969	6
									1968	7
									1968	8
										9
64	0.07	0.15	5150	215	1.00	0.99	10880	1964	1967	10
122	0.07	0.15	5150	215	1.00	0.99	10900	1964	1968	11
										12
										13
									1965 INJECTED INTO D-3	14
									1968 INJECTED INTO D-3	15
53	0.09	0.20	1580	125	0.82	0.68	4440	1949	1955 INJECTED INTO D-3	16
									1966	17
										18
									1965 INJECTED INTO D-3	19
									1968	20
							5650	1949	1966 INJECTED INTO D-3	21
										22
										23
									1964	24
13	0.20	0.30	2010	160	0.86	0.66	5900	1956	1964	25
										26
										27
15	0.19	0.30	620	90	0.93	0.57	2740	1952	1962 WESTCOAST	28
									1962	29
11	0.12	0.30	1470	110	0.85	0.60	4240	1953	1962 WESTCOAST	30
									1965 WESTCOAST	31
										32
										33
18	0.13	0.55	1600	140	0.83	0.69	4730	1958	1969	34
11	0.15	0.45	1600	140	0.83	0.69	4810	1967	1969	35
									1968	36
35	0.12	0.25	1620	145	0.85	0.64	4730	1961	1969	37
										38
										39
105	0.18	0.30	1220	135	0.85	0.65	3840	1952	1963 TCPL	40
									1963	41
										42
										43
									1961	44
21	0.24	0.30	630	70	0.91	0.60	1790	1954	1961 WESTERN MINERALS	45
									1966	46
									1966	47
										48
										49
									1961 TCPL	50
										51
										52
									1962	53
									1961	54
		GIP BASED ON MATERIAL BALANCE					3310	1951	1968 LOCAL UTILITY	55
									1961	56
										57
										58
									1966	59
									1957	60
									1957 LOCAL UTILITY	61
										62
										63
30	0.10	0.25	3430	185	0.84	0.84	8390	1954	1969 POOL BEING CYCLED	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
HARMATTAN EAST (CONTINUED)									
RUNDLE SOLN	170	0.55	0.25	71	19	52	1080*	56	
HARMATTAN-ELKTON									
BLAIRMORE	3	0.90	0.05	2		2	1020	2	
RUNDLE A	55	0.85	0.15	40	5	35	1100	39	2740
RUNDLE B ASSOC	28	0.85	0.15	21	9	12	1080*	13	7140
RUNDLE C ASSOC	1150	0.90	0.15	880	-54	934	1080*	1009	19020
RUNDLE C SOLN	180	0.65	0.30	83	44	39	1080*	42	
D-3 A	600	0.80	0.65	170	9	161	960	155	13970
HEART RIVER									
CADOTTE	2	0.85	0.05	2	1	1	1000	1	
NOTIKEWIN	2	0.90	0.05	2	1	1	1000	1	
HERCULES									
VIKING	20	0.85	0.05	17		17	1050	18	
MANNVILLE	16	0.80	0.05	13	1	12	960	12	
HIGH PRAIRIE									
CADOTTE	3	0.85	0.05	3		3	1000	3	
NOTIKEWIN	8	0.85	0.05	6		6	1100	7	
GETHING	2	0.85	0.05	1		1	1000	1	
HOLBURN									
CARDIUM	8	0.80	0.05	6	3	3	980	3	
MANNVILLE	16	0.85	0.10	12	1	11	1120	12	
HOLMBERG									
MANNVILLE A	15	0.85	0.05	12		12	1050	13	2100
MANNVILLE (OTHER)	11	0.85	0.05	9		9	1050	9	
HOMEGLEN-RIMBEY									
D-3 ASSOC	1170	0.75	0.15	760**					12800
D-3 SOLN	86	0.50	0.15	37**	275**	522	1020*	532	
HUNTER VALLEY									
RUNDLE A	73	0.85	0.25	47		47	1000	47	1570
RUNDLE (OTHER)	5	0.85	0.25	3		3	1000	3	
HUSSAR									
BELLY RIVER	4	0.75	0.05	3	2	1	1000	1	
VIKING E	24	0.80	0.05	18	5	13	1020*	13	13590
VIKING (OTHER)	17	0.80	0.05	13	3	10	1020*	10	
VIKING B ASSOC	32	0.75	0.05	22	3	19	1020*	19	13000
BASAL COLORADO A	26	0.75	0.05	19	8	11	1020*	11	16390
BASAL COLORADO C	26	0.75	0.05	19	9	10	1030*	10	16080
BSL COLORADO (OTHER)	4	0.80	0.05	3	1	2	1030*	2	
GLAUCONITIC N	130	0.85	0.05	100	58	42	1030*	43	12460
GLAUCONITIC P	17	0.85	0.05	14		14	1030*	14	500
GLAUCONITIC R	20	0.85	0.05	16	10	6	1030*	6	500
GLAUCONITIC A ASSOC	75	0.85	0.05	61	27	34	1030*	35	5290
GLAUCONITIC B ASSOC	19	0.85	0.05	15	11	4	1030*	4	3900
GLAUCONITIC A SOLN	20	0.65	0.25	10		10	1030*	10	
OSTRACOD R	26	0.85	0.05	21	2	19	1030*	20	7480
OSTRACOD F ASSOC	27	0.80	0.05	20	1	19	1030*	20	8300
BASAL MANNVILLE B	30	0.85	0.05	25		25	1030*	26	1330
BASAL MANNVILLE D	11	0.90	0.05	10	1	9	1030*	9	530
MANNVILLE (OTHER)	102	0.85	0.05	82	26	56	1030*	58	
MANN ASSOC (OTHER)	29	0.85	0.05	23	2	21	1030*	22	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
							8620	1957	1966 INJ INTO GAS CAP	2
										3
										4
									1966	5
35	0.08	0.20	3630	205	0.89	0.71	9150	1957	1964 TCPL	6
6	0.09	0.20	3430	195	0.85	0.82	8960	1955	1964 INJ INTO RUNDLE C	7
70	0.11	0.20	3630	200	0.84	0.84	8990	1954	1964 POOL BEING CYCLED	8
										9
							9130	1955	1966 INJ INTO GAS CAP	10
67	0.05	0.10	4680	230	0.75	0.93	11000	1961	1967 A&S	11
										12
										13
									1964 LOCAL UTILITY	14
									1964 LOCAL UTILITY	15
										16
										17
									1955	18
									1966 NUL	19
										20
										21
									1961 CONSIDERED BEYOND	22
									1961 ECONOMIC REACH	23
									1961	24
										25
										26
									1966 GOLDEN SPIKE INJ	27
									1968 GOLDEN SPIKE INJ	28
										29
										30
13	0.20	0.30	1100	95	0.81	0.70	3420	1952	1960 BAROID OF CANADA	31
									1958	32
										33
										34
173	0.07	0.10	2830	180	0.85	0.70	7840	1953	1964 TCPL AND A&S	35
							7920	1953	1964 TCPL AND A&S	36
										37
										38
83	0.07	0.20	3580	145	0.84	0.68	9280	1962	1964	39
									1964	40
										41
										42
									1961 TCPL	43
4	0.20	0.30	1150	100	0.89	0.63	3740	1961	1966 TCPL	44
									1961 TCPL	45
5	0.20	0.30	1120	105	0.88	0.63	4040	1955	1961 TCPL	46
										47
3	0.17	0.30	1240	110	0.88	0.61	4330	1952	1961 TCPL	48
4	0.18	0.30	1230	110	0.88	0.63	4120	1955	1964 TCPL	49
									1965 TCPL	50
14	0.21	0.30	1470	110	0.83	0.64	4470	1955	1968 TCPL	51
48	0.21	0.30	1490	110	0.82	0.65	4510	1957	1968	52
										53
56	0.21	0.30	1490	110	0.83	0.64	4650	1960	1967 TCPL	54
17	0.22	0.25	1480	110	0.83	0.64	4690	1952	1967 TCPL	55
7	0.20	0.30	1470	110	0.83	0.67	4700	1956	1967 TCPL	56
							4650	1957	1967	57
5	0.20	0.35	1510	115	0.82	0.65	4660	1956	1965 TCPL	58
										59
5	0.21	0.25	1370	110	0.84	0.65	4570	1956	1964 TCPL	60
45	0.15	0.30	1470	105	0.82	0.67	4330	1960	1963	61
38	0.16	0.30	1510	115	0.83	0.66	4820	1955	1961 TCPL	62
									1968 TCPL	63
									1968 TCPL	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
INLAND									
VIKING A	17	0.80	0.05	13		13	980	13	15300
MANNVILLE	2	0.80	0.10	1		1	1000	1	
INNISFAIL									
BLAIRMORE ASSOC	1	0.80	0.15	1		1	1050	1	
RUNDLE	22	0.90	0.10	18		18	1080	19	
WABAMUN	3	0.85	0.15	2		2	1080	2	
D-3 ASSOC	17	0.90	0.35	10		10	1020	10	1220
D-3 SOLN	200	0.55	0.45	60	18	42	1130*	47	
IRRICANA									
WABAMUN A	27	0.85	0.50	11		11	980	11	3296
JARVIE									
VIKING	10	0.80	0.05	7		7	1040	7	
MANNVILLE	9	0.85	0.05	8		8	1100	9	
JENNER									
BOW ISLAND	5	0.75	0.05	3		3	990	3	
BASAL COLORADO	8	0.85	0.05	6		6	1040	6	
BASAL COLORADO ASSOC	1	0.85	0.15	1		1	1040	1	
MANNVILLE	20	0.80	0.05	15		15	1050	16	
MANNVILLE ASSOC	15	0.80	0.05	12		12	1050	13	
PEKISKO ASSOC	3	0.85	0.05	2		2	1000	2	
JOARCAM									
VIKING	3	0.75	0.05	2		2	1040	2	
VIKING ASSOC	70	0.75	0.35	35	-2	37	1040	38	13520
VIKING SOLN	42	0.35	0.65	9	2	7	1050	7	
MANNVILLE 30-50-22	15	0.90	0.05	13		13	960	12	500
MANNVILLE (OTHER)	3	0.90	0.05	3		3	960	3	
JOFFRE									
VIKING	1	0.75	0.10	1		1	1000	1	
BLAIRMORE	41	0.85	0.10	32	1	31	1020	32	
LEDUC ASSOC	2	0.85	0.15	2		2	1050	2	
JUDY CREEK									
VIKING A	54	0.80	0.05	41	10	31	1010	31	23320
BHL LK A SOLN	560	0.45	0.30	180	20	160	1090*	174	
BHL LK B SOLN	270	0.50	0.30	93	10	83	1090*	90	
JUDY CREEK SOUTH									
RUNDLE A	13	0.90	0.10	10		10	1050*	11	500
JUMPING POUND									
MISSISSIPPIAN	780	0.85	0.15	560	277	283	1050*	297	7090
JUMPING POUND WEST									
RUNDLE A	750	0.80	0.20	480	14	466	1050*	489	9060
RUNDLE B	270	0.80	0.20	170	4	166	1050*	174	3570
RUNDLE C	150	0.80	0.20	94		94	1050*	99	2000
KAYBOB									
NOTIKEWIN A	200	0.85	0.05	160	29	131	1100*	144	25650
NOTIKEWIN B	170	0.85	0.05	140	55	85	1100*	94	
NOTIKEWIN D	17	0.85	0.05	14		14	1100*	15	5660
NOTIKEWIN (OTHER)	6	0.85	0.05	5		5	1100*	6	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
3	0.22	0.40	800	80	0.90	0.60	2190	1959	1963 CONSIDERED BEYOND	2
									1963 ECONOMIC REACH	3
										4
										5
									1965	6
									1961	7
									1961	8
28	0.06	0.15	3550	95	0.84	0.81	8440	1957	1961	9
										10
							8580	1957	1965 TCPL	11
										12
										13
13	0.06	0.85	3530	625	0.71	0.90	7602	1958	1968 WESTCOAST	14
										15
										16
									1960 CONSIDERED BEYOND	17
									1956 ECONOMIC REACH	18
										19
										20
									1961	21
									1961	22
									1969	23
									1961	24
										25
									1966	26
									1965	27
										28
										29
									1963	30
19	0.17	0.40	870	100	0.89	0.65	3240	1949	1968	31
							3250	1949	1968 GAS FLOOD	32
57	0.20	0.35	1250	100	0.86	0.60	3980	1960	1961	33
										34
									1961	35
										36
										37
									1967	38
									1967	39
									1967	40
										41
										42
5	0.18	0.35	1290	130	0.88	0.63	4610	1959	1968 NUL AND A&S	43
							8660	1959	1966 NUL AND A&S	44
							8840	1959	1966 NUL AND A&S	45
										46
										47
56	0.10	0.20	1900	155	0.86	0.63	6040	1960	1960 CONSIDERED BEYOND	48
									ECONOMIC REACH	49
										50
										51
141	0.08	0.10	3980	195	0.90	0.71	9590	1944	1964 CWNG	52
										53
										54
134	0.07	0.15	4250	185	0.92	0.74	10950	1961	1968 CWNG	55
130	0.07	0.15	4320	190	0.93	0.75	11950	1963	1968 CWNG	56
130	0.06	0.15	4350	180	0.91	0.75	11500	1967	1968	57
										58
										59
13	0.20	0.35	1530	135	0.88	0.61	4690	1957	1967 A&S	60
		GIP BASED ON MATERIAL BALANCE					4820	1958	1968 A&S	61
6	0.19	0.35	1390	145	0.88	0.61	5050	1958	1966	62
									1966	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
KAYBOB (CONTINUED)									
SPIRIT RIVER	8	0.85	0.05	7		7	1000	7	
GETHING	16	0.85	0.05	13		13	1050	14	
CADOMIN	48	0.85	0.05	38		38	1040	40	
CADOMIN B ASSOC	76	0.85	0.05	62		62	1040	64	6110
CADOMIN ASSOC	6	0.80	0.05	4		4	1040	4	
WABAMUN	1	0.80	0.10	1		1	1070	1	
NISKU	5	0.85	0.35	3		3	1070	3	
BEAVERHILL LAKE	1	0.80	0.15	1		1	1070	1	
BHL LK ASSOC	6	0.80	0.15	4		4	1140*	5	
BHL LK A SOLN	340	0.40	0.25	100	14	86	1140*	98	
KAYBOB SOUTH									
VIKING A	30	0.75	0.05	21	1	20	1120	22	30350
CADOMIN A	39	0.80	0.05	30		30	1070*	32	8390
CADOMIN B	27	0.80	0.05	20		20	1070*	21	3430
CADOMIN C	17	0.80	0.05	13		13	1070*	14	3122
CADOMIN (OTHER)	8	0.75	0.05	6		6	1070*	6	
TRIASSIC	3	0.80	0.05	2		2	1160*	2	
TRIASSIC ASSOC	2	0.80	0.05	2		2	1160*	2	
TRIASSIC SOLN	100	0.40	0.25	30		30	1160*	35	
NISKU A	19	0.90	0.20	14		14	1160*	16	1100
NISKU (OTHER)	1	0.80	0.05	1		1	1160*	1	
BEAVERHILL LAKE A	4040	0.80	0.35	2100		2100	1090*	2289	60360
KILLAM									
VIKING	6	0.80	0.05	4		4	1010	4	
MANNVILLE	14	0.75	0.05	10		10	1000	10	
NISKU	1	0.80	0.05	1		1	1170	1	
KILLAM NORTH									
MANNVILLE	19	0.80	0.05	15	1	14	1000	14	
MANNVILLE ASSOC	5	0.80	0.05	4		4	1000	4	
KNAPPEN									
MANNVILLE	6	0.80	0.05	5		5	1000	5	
SAWTOOTH	8	0.80	0.05	6		6	1000	6	
MISSISSIPPIAN	7	0.90	0.10	6		6	1000	6	
KNELLER									
MANNVILLE	11	0.85	0.05	9		9	1000	9	
KNOPCIK									
DOE CREEK A	18	0.75	0.05	12	1	11	1000	11	4360
PADDY	1	0.80	0.05	1		1	1020	1	
LAC LA BICHE									
MANNVILLE	10	0.80	0.05	8	1	7	1010	7	
LAMBERT CREEK									
WABAMUN 4-51-21	14	0.75	0.05	10		10	1050	11	1100
LEAHURST									
MANNVILLE	25	0.65	0.05	15	2	13	1160*	15	
LEDUC-WOODBEND									
CARDIUM	12	0.80	0.05	9	7	2	1040	2	
VIKING	20	0.80	0.05	15	3	12	1070	13	
BLAIRMORE	34	0.85	0.05	26	22	4	1180	5	
BLAIRMORE ASSOC	57	0.85	0.05	45	2	43	1180	51	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1964	2
									1964	3
									1964	4
17	0.16	0.30	2210	160	0.84	0.72	5800	1962	1964	5
									1968	6
										7
									1961	8
									1961	9
									1964	10
									1962	11
							9780	1957	1965 A&S	12
										13
										14
3	0.14	0.40	1460	150	0.86	0.66	5710	1960	1968	15
8	0.15	0.35	2230	180	0.87	0.64	6710	1961	1966	16
13	0.15	0.35	2230	180	0.87	0.64	6750	1963	1966	17
9	0.15	0.35	2230	180	0.87	0.64	6750	1961	1966	18
										19
									1967	20
									1964 TCPL	21
									1963	22
							6980	1962	1965	23
4	0.05	0.20	4100	225	0.93	0.80	9510	1958	1963	24
										25
									1958	26
94	0.07	0.20	4690	240	0.90	1.00	10560	1961	1969 POOL BEING CYCLED	27
										28
										29
									1968	30
									1968	31
									1968	32
										33
										34
									1966 LOCAL UTILITY	35
									1966	36
										37
										38
									1966 CMG	39
									1967 CMG	40
									1965	41
										42
										43
									1968	44
										45
										46
9	0.22	0.30	900	100	0.87	0.66	2920	1964	1966 LOCAL UTILITY	47
									1964	48
										49
										50
									1968 LOCAL UTILITY	51
										52
										53
48	0.03	0.20	5500	250	1.05	0.79	12870	1957	1958 CONSIDERED BEYOND	54
									ECONOMIC REACH	55
										56
										57
									1969 LOCAL UTILITY	58
										59
										60
									1967 INJECTED INTO NISKU	61
									1959 AND LEDUC GAS CAPS	62
									1959 AND SOLD TO NUL	63
									1961	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
LEDUC-WOODBEND (CONTINUED)									
D-1	2	0.85	0.10	2	2	¤ 1	1050	¤ 1	
D-1 ASSOC	4	0.85	0.10	3		3	1050	3	
D-2A ASSOC	37	0.90	0.15	28	-12	40	1180	47	9770
D-2 A SOLN	130	0.75	0.30	70	63	7	1180	8	
D-2 B SOLN	41	0.75	0.30	21	15	6	1180	7	
D-3 A ASSOC	420	0.85	0.15	300	-7	307	1180	362	17490
D-3 ASSOC (OTHER)	6	0.85	0.15	4	1	3	1180	4	
D-3 A SOLN	140	0.70	0.30	70	59	11	1180	13	
D-3 SOLN (OTHER)	9	0.70	0.30	5	4	1	1180	1	
LEGAL									
MANNVILLE	6	0.75	0.05	4	2	2	1030	2	
LINDBERGH									
VIKING	4	0.65	0.05	2		2	990	2	
MANNVILLE	23	0.80	0.05	17	7	10	1000	10	
LITTLE BOW									
MANNVILLE	17	0.85	0.05	14	1	13	1000	13	
UPPER MANN A ASSOC	20	0.85	0.05	16	2	14	1000	14	3440
MANN ASSOC OTHER	1	0.85	0.05	1		1	1000	1	
LLOYDMINSTER									
MANNVILLE	24	0.85	0.30	14	12	2	950	2	
LONE PINE CREEK									
MANNVILLE	5	0.85	0.10	4		4	1020	4	
WABAMUN A	370	0.85	0.20	250	12	238	1000	238	28200
D-3 A ASSOC	77	0.85	0.25	48**					2420
D-3 A SOLN	10	0.65	0.30	5**	2**	51	1060*	54	
D-3 ASSOC (OTHER)	9	0.85	0.20	6		6	1060*	6	
LONG COULEE									
MANNVILLE A	16	0.85	0.25	10	1	9	1000	9	2070
MANNVILLE (OTHER)	11	0.85	0.20	7		7	1000	7	
LOOKOUT BUTTE									
RUNDLE A	660	0.80	0.15	450	28	422	1060*	447	7280
LOVETT RIVER									
BLAIRMORE 2-47-19	12	0.90	0.05	10		10	1040	10	1100
RUNDLE A	97	0.80	0.10	70		70	1040	73	1100
MAJEAU LAKE									
MANNVILLE	2	0.80	0.05	2		2	1000	2	
MISS 25-56-4	12	0.90	0.10	10		10	1070	11	500
MALMO									
VIKING	8	0.85	0.05	6		6	1000	6	
BLAIRMORE	8	0.85	0.10	6		6	1030	6	
BLAIRMORE ASSOC	2	0.70	0.15	1		1	1030	1	
NISKU ASSOC	4	0.80	0.20	3		3	1100	3	
D-3 B	42	0.85	0.20	29		29	1100	32	1960
D-3 ASSOC	2	0.85	0.15	1		1	1100	1	
MANYBERRIES									
BOW ISLAND A	28	0.90	0.02	25	23	2	940	2	
BOW ISLAND (OTHER)	5	0.65	0.02	3		3	940	3	
MANNVILLE	2	0.80	0.05	1		1	1000	1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1969	2
									1966	3
41	0.02	0.20	1780	150	0.80	0.73	5050	1947	1958	4
							5100	1947	1965	5
							5260	1947	1965	6
										7
60	0.08	0.15	1890	150	0.83	0.66	5300	1947	1964	8
									1964	9
							5320	1947	1966	10
									1966	11
										12
										13
									1955 CIGOL	14
										15
										16
									1961 CANSALT	17
									1961 CANSALT	18
										19
										20
									1968	21
8	0.21	0.40	1680	105	0.82	0.67	3950	1965	1968 TCPL	22
									1968	23
										24
										25
									1966 LOCAL UTILITY	26
										27
										28
									1963	29
33	0.05	0.20	3570	180	0.89	0.76	7850	1955	1969 TCPL	30
47	0.08	0.15	3260	175	0.84	0.81	7990	1963	1967 TCPL	31
							8010	1963	1967 TCPL	32
										33
									1967	34
										35
										36
9	0.20	0.35	1880	105	0.78	0.83	4380	1965	1968 TCPL	37
									1968	38
										39
										40
153	0.07	0.20	4770	190	0.96	0.72	12060	1959	1967 TCPL	41
										42
										43
9	0.15	0.25	4300	190	0.96	0.62	10010	1959	1959	44
177	0.06	0.20	4950	220	1.01	0.61	11870	1958	1959	45
										46
										47
									1955 CONSIDERED BEYOND	48
60	0.09	0.15	1500	125	0.82	0.67	4250	1951	1955 ECONOMIC REACH	49
										50
										51
									1960	52
									1959	53
									1960	54
									1959	55
										56
46	0.07	0.10	2180	130	0.81	0.76	5990	1959	1966	57
									1966	58
										59
										60
		GIP BASED ON MATERIAL BALANCE					2570	1947	1967 CMG	61
									1967	62
									1957	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
1	2	3	4	5	6	7	8	9	10
MARLBORO									
LEDUC A	63	0.85	0.25	40		40	1000	40	500
MARSH HEAD CREEK									
LEDUC 17-59-20	27	0.85	0.35	15		15	1050	16	500
MARTEN HILLS									
PELICAN	2	0.65	0.05	1		1	990	1	
WABISKAW A	770	0.75	0.05	550		550	990	545	166000
MANNVILLE (OTHER)	16	0.75	0.05	11		11	990	11	
WABAMUN A	330	0.75	0.05	240		240	1000	240	79640
WABAMUN (OTHER)	10	0.75	0.05	7		7	1000	7	
MATZIWIN									
VIKING	11	0.85	0.05	9		9	1090	10	
MANNVILLE	1	0.80	0.05	1		1	1090	1	
MAZEPPA									
MISS 16-19-27	20	0.90	0.15	15		15	1060	16	1100
WABAMUN	11	0.85	0.45	5		5	1000	5	
MEDICINE HAT									
MEDICINE HAT	2550	0.80	0.02	2000	597	1403	970	1361	983680
BOW ISLAND	15	0.60	0.05	9	1	8	970	8	
SAWTOOTH	6	0.80	0.05	5	2	3	1000	3	
MEDICINE RIVER									
BASAL MANNVILLE A	34	0.85	0.15	25		25	1150*	29	3680
MANNVILLE (OTHER)	73	0.85	0.15	53		53	1150*	61	
OSTRACOD B ASSOC	14	0.85	0.15	10		10	1150*	12	3980
OSTRACOD C ASSOC	40	0.85	0.15	29	3	26	1150*	30	2900
BASAL QUARTZ B ASSOC	32	0.85	0.15	23		23	1150*	26	2310
MANN ASSOC (OTHER)	18	0.85	0.15	13		13	1150*	15	
MANN SOLN	43	0.60	0.45	12		12	1150*	14	
JURASSIC	15	0.85	0.15	11		11	1020*	11	
JURASSIC D ASSOC	15	0.80	0.15	10		10	1020*	10	910
JUR ASSOC (OTHER)	16	0.80	0.15	11		11	1020*	11	
JURASSIC SOLN	70	0.65	0.45	25		25	1020*	26	
RUNDLE	20	0.85	0.15	14	1	13	1100*	14	
RUNDLE ASSOC	9	0.85	0.15	6		6	1100*	7	
RUNDLE SOLN	36	0.60	0.45	12		12	1200*	14	
LEDUC ASSOC	2	0.85	0.20	1		1	1100*	1	
MILLET									
MANNVILLE 1-49-25	25	0.50	0.05	12		12	1020	12	5880
MANNVILLE (OTHER)	5	0.80	0.10	3		3	1020	3	
MINNEHIK-BUCK LAKE									
BLAIRMORE	6	0.80	0.05	4		4	1000	4	
PEKISKO A	630	0.85	0.07	500	114	386	1120*	432	
PEKISKO B	71	0.85	0.10	54	1	53	1120*	59	7620
MITSUE									
MANNVILLE	2	0.80	0.05	1		1	1070	1	
GILWOOD ASSOC	3	0.90	0.25	2		2	1170	2	
GILWOOD A SOLN	470	0.50	0.25	180		180	1170	211	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
173	0.07	0.10	4960	250	0.96	0.74	12140	1965	1966	2
										3
										4
29	0.06	0.15	4800	245	0.92	0.66	11540	1961	1964 CONSIDERED BEYOND	5
									ECONOMIC REACH	6
										7
										8
									1964	9
19	0.29	0.30	390	80	0.95	0.57	2250	1961	1968	10
									1969	11
40	0.15	0.40	390	80	0.95	0.57	2260	1961	1968	12
										13
									1967	14
										15
										16
									1962	17
									1961	18
										19
										20
33	0.08	0.20	2700	145	0.81	0.71	6800	1956	1957 CONSIDERED BEYOND	21
									ECONOMIC REACH	22
									1967	23
										24
										25
8	0.26	0.40	630	60	0.91	0.57	1600	1904	1967 TCPL, MANY ISLANDS	26
									AND LOCAL UTILITY	27
									1964 TCPL	28
									1968 TCPL	29
										30
										31
12	0.14	0.30	2640	160	0.81	0.71	7660	1958	1968	32
									1968	33
5	0.13	0.35	2830	155	0.80	0.76	7010	1954	1968	34
14	0.14	0.25	2930	150	0.79	0.76	7480	1960	1968 TCPL	35
										36
19	0.14	0.30	2380	150	0.81	0.72	7000	1959	1968	37
									1968	38
									1968	39
									1968	40
22	0.15	0.30	2340	145	0.81	0.70	6970	1962	1968	41
										42
									1968	43
									1968	44
									1968 TCPL	45
									1968	46
									1968	47
										48
									1968	49
										50
										51
7	0.20	0.70	1500	120	0.79	0.71	4440	1951	1968 CONSIDERED BEYOND	52
									1957 ECONOMIC REACH	53
										54
										55
									1959	56
		GIP BASED ON MATERIAL BALANCE					6910	1952	1968 A&S	57
19	0.10	0.25	2490	185	0.85	0.71	7300	1962	1966 A & S	58
										59
										60
									1968	61
									1966	62
							5680	1964	1968	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
MOOSE									
RUNDLE A	86	0.80	0.20	55		55	1000	55	1900
MORINVILLE									
VIKING	4	0.75	0.05	3		3	1000	3	
MANNVILLE	130	0.80	0.10	96	45	51	1070*	55	
MOUNTAIN PARK									
TRIASSIC 36-47-22	21	0.85	0.05	17		17	1090	19	1100
MURIEL LAKE									
MANNVILLE	9	0.75	0.05	6	1	5	1000	5	
NEVIS									
BLAIRMORE A	64	0.85	0.10	49		49	1000	49	11990
BLAIRMORE (OTHER)	2	0.85	0.10	1		1	1000	1	
DEVONIAN	1040	0.90	0.15	800	183	617	1000*	617	31000
NEW NORWAY									
VIKING	3	0.80	0.10	2		2	1000	2	
BLAIRMORE	10	0.85	0.05	9		9	1010	9	
NIPISI									
GILWOOD A SOLN	250	0.55	0.25	110		110	1150	127	
NITON									
BLAIRMORE	13	0.80	0.05	10		10	1070	11	
CADOMIN	8	0.90	0.05	7		7	1070	7	
NORDEGG									
TRIASSIC	9	0.90	0.10	7		7	1000	7	
RUNDLE 17-41-17	25	0.90	0.10	20		20	1000	20	2130
NORMANDVILLE									
PEACE RIVER	1	0.70	0.05	1		1	990	1	
GETHING	6	0.85	0.05	5		5	980	5	
TRIASSIC	1	0.85	0.05	1		1	1090	1	
BELLOY	2	0.85	0.05	2		2	1060	2	
MISSISSIPPIAN A	16	0.85	0.05	13	2	11	1050	12	1410
MISS (OTHER)	22	0.85	0.05	18	1	17	1050	18	
OBED									
VIKING 26-55-22	14	0.85	0.05	12		12	1020	12	1100
MANNVILLE	6	0.85	0.05	5		5	1040	5	
RUNDLE	4	0.85	0.10	4		4	1050	4	
D-2 A	580	0.90	0.35	130		130	1060	138	
OBERLIN									
MANNVILLE	3	0.70	0.05	2	2	□ 1	1090	□ 1	
OKOTOKS									
CROSSFIELD	470	0.80	0.55	170	51	119	1000	119	21990
OLDS									
WABAMUN B	31	0.85	0.25	20		20	1000*	20	1100
WABAMUN A ASSOC	350	0.85	0.25	220	46	174	1000*	174	31030
WABAMUN SOLN	62	0.65	0.40	24		24	1000*	24	
OPEN CREEK									
BASAL QUARTZ A	14	0.85	0.10	11		11	1080*	12	500

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
140	0.06	0.15	1870	115	0.77	0.73	7570	1960	1969
									1962
									1962 CIGOL AND LOCAL
									UTILITY .
36	0.07	0.20	4100	240	0.98	0.62	10120	1956	1969 CONSIDERED BEYOND
									ECONOMIC REACH
									1964 LOCAL UTILITY
7	0.22	0.20	1400	130	0.84	0.66	4750	1952	1959
									1964
75	0.07	0.15	2340	140	0.81	0.69	5580	1952	1968 TCPL
									1959
									1959
									1965 CONSIDERED BEYOND
									ECONOMIC REACH
									1966
									1963
									1961 CONSIDERED BEYOND
70	0.04	0.20	1840	125	0.86	0.58	4930	1960	1961 ECONOMIC REACH
									1967
									1967
									1967
									1967
13	0.27	0.35	1570	100	0.83	0.64	3440	1956	1967 LOCAL UTILITY
									1967 LOCAL UTILITY
15	0.14	0.40	3830	165	0.92	0.62	8080	1967	1967
									1969
									1966
									1969
									1967 LOCAL UTILITY
39	0.06	0.20	3600	175	0.70	0.90	8710	1951	1966 CWNG
68	0.05	0.20	3600	165	0.83	0.75	8600	1959	1967 TCPL
27	0.05	0.20	3590	165	0.83	0.75	8680	1952	1967 TCPL
							8990	1965	1967 TCPL
38	0.14	0.35	2800	180	0.84	0.71	7190	1967	1968

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
OPEN CREEK (CONTINUED)									
MANNVILLE (OTHER)	19	0.90	0.15	14		14	1080*	15	
PEKISKO	11	0.85	0.10	8		8	1080*	9	
OWLSEYE									
MANNVILLE	2	0.85	0.05	2		2	1020	2	
OYEN									
VIKING A	36	0.85	0.05	29	5	24	980	24	6750
VIKING (OTHER)	8	0.80	0.05	6	5	1	980	1	
DETRITAL	11	0.85	0.05	9	2	7	1010	7	
PADDLE RIVER									
JURASSIC-DETRITAL	180	0.80	0.10	130	19	111	1130*	125	30000
RUNDLE	36	0.85	0.10	27		27	1060	29	9300
PAKOWKI LAKE									
BOW ISLAND A	21	0.65	0.05	13	8	5	940	5	21480
BOW ISLAND (OTHER)	5	0.85	0.05	4		4	940	4	
MANNVILLE	1	0.90	0.05	1		1	1000	1	
PARKLAND									
RUNDLE	3	0.85	0.15	2**	2**		1010		
PARKLAND NORTH-EAST									
RUNDLE 29-15-26	15	0.85	0.15	11		11	1010	11	2130
RUNDLE (OTHER)	5	0.90	0.15	4		4	1010	4	
PELICAN									
WABISKAW	18	0.70	0.05	12		12	990	12	
WABISKAW ASSOC	3	0.65	0.05	2		2	990	2	
PEMBINA									
KEYSTONE BR A	23	0.80	0.05	18		18	1070*	19	3230
BELLY RIVER (OTHER)	33	0.80	0.05	26	3	23	1070*	25	
BELLY RIVER ASSOC	25	0.80	0.05	19		19	1070*	20	
BELLY RIVER SOLN	90	0.45	0.80	9	3	6	1070*	6	
CARDIUM SOLN	4100	0.36	0.40	880	150	730	1130*	825	
VIKING	11	0.80	0.05	8		8	1130*	9	
GLAUCONITIC A	170	0.85	0.06	130	26	104	1130*	118	12600
GLAUCONITIC B	93	0.85	0.06	74	6	68	1130*	77	5180
GLAUCONITIC C & D	73	0.80	0.06	55		55	1130*	62	4970
MANNVILLE (OTHER)	19	0.75	0.05	14	3	11	1130*	12	
JURASSIC	18	0.85	0.05	15		15	1050*	16	
RUNDLE	13	0.85	0.10	10		10	1050*	11	
PENDANT D'OREILLE									
BOW ISLAND	200	0.85	0.05	160	99	61	940	57	86630
BOW ISLAND (OTHER)	4	0.85	0.05	3		3	940	3	
MANNVILLE A	47	0.90	0.05	40	20	20	1000	20	4480
MANNVILLE C	35	0.90	0.05	30	2	28	1000	28	2590
MANNVILLE (OTHER)	19	0.90	0.05	16		16	1000	16	
PENHOLD									
VIKING 33-36-28	14	0.90	0.05	12		12	1020	12	1650
PHIL CAN									
GETHING	11	0.85	0.05	8		8	980	8	
MISSISSIPPIAN	5	0.85	0.05	4		4	1050	4	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968	2
									1968	3
										4
										5
									1961 LOCAL UTILITY	6
										7
										8
10	0.24	0.30	970	85	0.89	0.58	2570	1942	1965 TCPL	9
									1965 TCPL	10
									1965 TCPL	11
										12
										13
22	0.14	0.65	1780	140	0.82	0.70	5050	1956	1969 NUL	14
14	0.08	0.35	1780	130	0.81	0.82	5090	1956	1966	15
										16
										17
3	0.21	0.30	790	75	0.91	0.59	2200	1955	1967 CMG	18
									1967	19
									1967	20
										21
										22
									1963 POOL ABANDONED	23
										24
										25
16	0.07	0.25	2830	145	0.83	0.66	6940	1953	1963 CONSIDERED BEYOND	26
									1956 ECONOMIC REACH	27
										28
										29
									1968 CONSIDERED BEYOND	30
									1964 ECONOMIC REACH	31
										32
										33
18	0.19	0.35	1050	100	0.89	0.60	3180	1957	1965	34
									1965 NUL	35
									1965	36
									1965 NUL	37
										38
							5080	1953	1967 NUL	39
									1956	40
25	0.14	0.40	1990	135	0.80	0.69	6000	1957	1968 A&S	41
23	0.16	0.30	1970	135	0.81	0.69	5640	1958	1968 NUL	42
24	0.15	0.35	1950	135	0.81	0.66	6080	1959	1968 NUL	43
										44
									1959 NUL	45
									1965	46
									1966	47
										48
										49
6	0.22	0.25	710	75	0.92	0.59	2030	1946	1968 CMG	50
									1967	51
20	0.21	0.35	1150	85	0.87	0.58	2740	1961	1968 CMG	52
25	0.22	0.35	1160	85	0.87	0.58	2690	1965	1968 CMG	53
										54
									1968 CMG	55
										56
										57
12	0.20	0.30	1710	145	0.89	0.69	5590	1958	1958 CONSIDERED BEYOND	58
									ECONOMIC REACH	59
										60
										61
									1961 CONSIDERED BEYOND	62
									1961 ECONOMIC REACH	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
PINCHER CREEK									
RUNDLE A	1800	0.40	0.25	540	252	288	1020*	294	14000
PINE CREEK									
WABAMUN	190	0.80	0.45	82	44	38	1050	40	9650
WABAMUN (OTHER)	30	0.85	0.45	14		14	1000	14	
D-3	770	0.40	0.35	200	149	51	1000	51	9480
PINE NORTH-WEST									
DEBOLT	8	0.85	0.10	6		6	1030	6	
D-3 A	360	0.75	0.25	200	14	186	980	182	4310
PLAIN									
VIKING	3	0.75	0.05	2		2	980	2	
MANNVILLE	15	0.80	0.05	11		11	1000	11	
PLOVER LAKE									
VIKING	18	0.90	0.05	15		15	1000	15	
POUCE COUPE									
PEACE RIVER A	150	0.70	0.05	100	89	11	1000	11	25700
PEACE RIVER (OTHER)	2	0.80	0.05	2		2	1000	2	
CADOMIN	4	0.85	0.05	3		3	1060	3	
POUCE COUPE SOUTH									
DOE CREEK	5	0.60	0.05	3	2	1	1000	1	
PEACE RIVER A	32	0.75	0.05	23	19	4	1040	4	6700
PEACE RIVER B	55	0.75	0.05	39	31	8	1040	8	8500
PEACE RIVER (OTHER)	5	0.70	0.05	3		3	1040	3	
CADOTTE	9	0.70	0.05	6		6	1040	6	
GETHING	16	0.80	0.05	12	11	1	1000	1	
CADOMIN	7	0.85	0.05	6	2	4	1000	4	
TRIASSIC	18	0.80	0.05	14		14	1000	14	
PREVO									
MANNVILLE	5	0.85	0.10	4		4	1020	4	
PEKISKO A	44	0.85	0.10	34	8	26	1110*	29	2490
PRINCESS									
2WS A	60	0.80	0.05	45	5	40	970	39	33310
2WS (OTHER)	7	0.75	0.05	5		5	970*	5	
BOW ISLAND	2	0.75	0.05	1		1	1010	1	
BASAL COLORADO	9	0.75	0.05	6	3	3	1020*	3	
BASAL MANNVILLE A	18	0.90	0.05	15	5	10	1020*	10	1050
BASAL MANNVILLE C	38	0.85	0.05	31	1	30	1020*	31	2220
MANNVILLE (OTHER)	21	0.85	0.05	17	9	8	1020*	8	
MANN ASSOC (OTHER)	14	0.90	0.05	12	10	2	1020*	2	
JEFFERSON B	30	0.85	0.05	24	4	20	1030*	21	6940
JEFFERSON ASSOC	1	0.85	0.05	1		1	1030*	1	
PROVOST									
VIKING A & B	1050	0.88	0.02	900	278	622	1030	641	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESSIBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
310	0.04	0.20	4940	190	0.97	0.72	12500	1948	1961 TCPL	2
										3
										4
26	0.07	0.15	4500	210	0.82	0.83	10080	1956	1967 MAINTAINS PRESSURE	5
									1965 IN WINDFALL D-3 A	6
122	0.07	0.15	4580	235	0.91	0.76	11020	1957	1966	7
										8
										9
									1968	10
133	0.08	0.10	4650	240	0.95	0.71	10670	1963	1967 MAINTAINS PRESSURE	11
									IN WINDFALL D-3 A	12
										13
										14
									1961	15
									1969	16
										17
										18
									1962 CONSIDERED BEYOND	19
									ECONOMIC REACH	20
										21
										22
25	0.18	0.30	620	95	0.93	0.57	2300	1922	1966 WESTCOAST	23
									1961	24
									1965	25
										26
										27
									1964 WESTCOAST AND PEACE	28
									RIVER TRANSMISSION	29
17	0.17	0.30	800	105	0.91	0.57	3240	1953	1965 WESTCOAST AND PEACE	30
									RIVER TRANSMISSION	31
										32
23	0.17	0.30	800	105	0.91	0.57	3240	1953	1965 WESTCOAST AND PEACE	33
									RIVER TRANSMISSION	34
									1965	35
									1964	36
									1965 WESTCOAST AND PEACE	37
									RIVER TRANSMISSION	38
										39
									1968 WESTCOAST AND PEACE	40
									RIVER TRANSMISSION	41
									1965	42
										43
										44
									1966	45
25	0.10	0.20	2330	160	0.83	0.69	6580	1958	1966 TCPL	46
										47
										48
5	0.22	0.40	820	75	0.90	0.58	2190	1963	1967 TCPL	49
									1965	50
									1965 TCPL	51
									1966 TCPL	52
										53
23	0.20	0.30	1550	85	0.82	0.61	3170	1940	1966 TCPL	54
23	0.20	0.30	1550	85	0.83	0.64	3230	1940	1965 TCPL	55
									1967 TCPL	56
									1966 TCPL	57
14	0.08	0.25	1590	100	0.82	0.82	3190	1940	1965 TCPL	58
										59
									1965	60
										61
										62
		GIP BASED ON MATERIAL BALANCE					2510	1946	1968 TCPL AND LOCAL	63
									UTILITY	64

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
PROVOST (CONTINUED)									
VIKING (OTHER)	35	0.75	0.05	25		25	1030	26	
VIKING ASSOC	19	0.70	0.05	13		13	1030	13	
MANNVILLE	29	0.85	0.05	24		24	1000	24	
QUIRK CREEK									
RUNDLE A	740	0.85	0.20	500		500	1110*	555	9900
RAINBOW									
SLAVE POINT	6	0.90	0.15	4		4	1100*	4	
SULPHUR POINT	35	0.85	0.15	26		26	1100*	29	
SULPHUR POINT ASSOC	3	0.85	0.15	2		2	1100*	2	
SULPHUR POINT SOLN	4	0.65	0.20	2		2	1100*	2	
MUSKEG	8	0.90	0.15	6		6	1120*	7	
MUSKEG SOLN	10	0.65	0.30	5		5	1150*	6	
KEG RIVER Q	18	0.85	0.10	14		14	1150*	16	160
KEG RIVER FFF	19	0.90	0.10	16		16	1150*	18	160
KEG RIVER (OTHER)	17	0.85	0.15	12		12	1150*	14	
KEG RIVER A ASSOC	38	0.85	0.15	28	-5	33	1200*	40	340
KEG RIVER F ASSOC	74	0.85	0.90	57		57	1200*	68	2260
KR ASSOC (OTHER)	20	0.85	0.10	15		15	1200*	18	
KEG RIVER A SOLN	130	0.75	0.20	76	2	74	1260*	93	
KEG RIVER B SOLN	91	0.45	0.20	33	1	32	1260*	40	
KEG RIVER E SOLN	19	0.65	0.15	11		11	1260*	14	
KEG RIVER F SOLN	150	0.75	0.15	97	2	95	1260*	120	
KEG RIVER O SOLN	34	0.50	0.25	13		13	1260*	16	
KEG RIVER II SOLN	20	0.75	0.25	11		11	1260*	14	
KR SOLN (OTHER)	159	0.75	0.25	88		88	1260*	111	
RAINBOW SOUTH									
WINTERBURN	2	0.90	0.05	2		2	1060*	2	
SULPHUR POINT	33	0.85	0.10	24		24	1100*	26	
MUSKEG	15	0.85	0.20	11		11	1100*	12	
KEG RIVER	7	0.85	0.15	5		5	1150*	6	
KEG RIVER ASSOC	19	0.85	0.15	13		13	1150*	15	
KEG RIVER A SOLN	34	0.75	0.25	19		19	1200*	23	
KEG RIVER B SOLN	26	0.75	0.15	17		17	1200*	20	
KEG RIVER G SOLN	24	0.75	0.25	13		13	1200*	16	
KR SOLN (OTHER)	30	0.75	0.25	17		17	1200*	20	
REDLAND									
BELLY RIVER	1	0.65	0.05	1		1	1000	1	
VIKING	3	0.80	0.05	2		2	1000	2	
MANNVILLE	18	0.85	0.05	15	4	11	1070	12	
REDWATER									
VIKING	26	0.75	0.05	19	1	18	1040	19	
MANNVILLE	1	0.80	0.05	1	1	¤ 1	1050	¤ 1	
D-1	4	0.85	0.05	3	2	1	1070	1	
D-3 SOLN	240	0.60	0.65	49	13	36	1220*	44	
RED WILLOW									
VIKING	19	0.75	0.05	13		13	1020	13	
MANNVILLE	17	0.80	0.05	13		13	1100	14	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968	2
									1967	3
										4
									1961	5
										6
										7
143	0.08	0.15	2270	120	0.75	0.75	6160	1967	1969	8
										9
										10
									1967 CONSIDERED BEYOND	11
									1967 ECONOMIC REACH	12
									1967	13
									1968	14
										15
									1967	16
									1967	17
248	0.07	0.10	2400	630	0.85	0.70	5743	1966	1968	18
396	0.05	0.20	2570	600	0.80	0.70	6050	1966	1968	19
									1967	20
										21
147	0.11	0.06	2570	655	0.82	0.78	6015	1965	1968	22
79	0.07	0.15	2480	180	0.70	0.70	5870	1966	1967	23
									1967	24
							6380	1965	1968 INJ INTO GAS CAP	25
							5970	1965	1967	26
										27
							5930	1966	1967	28
							6090	1966	1967	29
							6050	1966	1968	30
							5940	1967	1968	31
									1967	32
										33
										34
									1967 CONSIDERED BEYOND	35
									1967 ECONOMIC REACH	36
									1967	37
									1967	38
										39
									1967	40
							6370	1965	1967	41
							6460	1966	1967	42
							6390	1967	1968	43
									1968	44
										45
										46
									1966	47
									1961	48
									1966 CWNG	49
										50
										51
									1965 LOCAL UTILITY AND	52
									CIGOL	53
									1960 LOCAL UTILITY AND	54
									CIGOL	55
										56
									1967 LOCAL UTILITY AND	57
									CIGOL	58
							3210	1948	1965 LOCAL UTILITY AND	59
									CIGOL	60
										61
										62
									1969 CONSIDERED BEYOND	63
									1969 ECONOMIC REACH	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
RETLAW									
BOW ISLAND	8	0.75	0.05	6	1	5	950	5	
BASAL COLORADO	8	0.75	0.05	6		6	1020	6	
MANNVILLE B & D	27	0.90	0.10	22	7	15	1000	15	3990
MANNVILLE J	21	0.90	0.05	18	1	17	1000	17	1250
MANNVILLE K	14	0.90	0.15	11		11	1000	11	1250
MANNVILLE (OTHER)	44	0.85	0.10	32		32	1000	32	
RUNDLE	2	0.85	0.10	1		1	1010	1	
RUNDLE ASSOC	2	0.90	0.10	2		2	1010	2	
RICH									
LOWER MANNVILLE A	16	0.85	0.10	12	1	11	1100	12	3810
RICHDALE									
VIKING A	12	0.85	0.05	10		10	1010	10	6650
VIKING (OTHER)	7	0.85	0.05	6		6	1010	6	
MANNVILLE	11	0.75	0.05	9		9	1050	9	
RICINUS									
D-3 A	150	0.85	0.35	80		80	1100	88	
ROCHESTER									
VIKING	4	0.80	0.05	3		3	1000	3	
MANNVILLE	25	0.75	0.05	18		18	1000	18	
WABAMUN	6	0.90	0.05	5		5	1070	5	
ROWLEY									
BELLY RIVER	6	0.80	0.05	4		4	1000	4	
VIKING	10	0.85	0.05	8		8	1040	8	
MANNVILLE	12	0.85	0.05	10		10	1070	11	
MANNVILLE ASSOC	10	0.85	0.05	8		8	1070	9	
PEKISKO A ASSOC	47	0.90	0.10	38	4	34	1080*	37	6780
PEKISKO SOLN	8	0.65	0.25	4		4	1100*	4	
RYCROFT									
BLUESKY	7	0.80	0.05	5	3	2	1040	2	
GETHING	13	0.90	0.05	11	1	10	1040	10	
SADDLE HILLS									
CADOTTE D	37	0.70	0.05	25		25	1020	26	5380
PEACE RIVER	11	0.70	0.05	7		7	1020	7	
GETHING	5	0.80	0.05	4		4	980	4	
BELLOY A	22	0.80	0.15	15		15	1030	15	1050
SAMSON									
BLAIRMORE	8	0.85	0.05	7		7	1070*	7	
BLAIRMORE ASSOC	9	0.80	0.05	7**					
BLAIRMORE SOLN	2	0.65	0.05	1**	6**	2	1070*	2	
SARCEE									
RUNDLE A	210	0.85	0.15	150	46	104	1050*	109	3100
SARCEE WEST									
KOOTENAY 17-23-4	13	0.80	0.05	10		10	1020	10	500
SAVANNA CREEK									
RUNDLE A	340	0.85	0.30	200	32	168	1020	171	7980
SEDALIA									
VIKING A	140	0.80	0.05	100	7	93	1010*	94	
VIKING (OTHER)	3	0.80	0.05	2		2	1010	2	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968 TCPL	2
									1965	3
7	0.22	0.30	1720	95	0.79	0.71	3570	1959	1968 TCPL	4
23	0.21	0.40	1700	95	0.81	0.71	3110	1966	1967	5
										6
8	0.29	0.15	1650	85	0.79	0.71	3550	1954	1969	7
									1968	8
									1966	9
									1966	10
										11
										12
13	0.12	0.30	1270	135	0.87	0.65	4800	1953	1961 TCPL	13
										14
										15
4	0.20	0.40	1080	90	0.87	0.60	3100	1955	1968	16
									1968	17
									1968	18
										19
										20
									1969	21
										22
										23
									1953 CONSIDERED BEYOND	24
									1953 ECONOMIC REACH	25
									1953	26
										27
										28
									1964	29
									1966	30
									1964	31
									1965	32
										33
22	0.08	0.20	1500	120	0.82	0.71	4410	1960	1963 TCPL	34
									1967	35
										36
										37
									1961 LOCAL UTILITY	38
									1961 LOCAL UTILITY	39
										40
										41
17	0.21	0.30	930	115	0.92	0.57	3640	1957	1965	42
									1965	43
									1965	44
35	0.10	0.25	2600	155	0.82	0.65	6970	1957	1965	45
										46
										47
									1968	48
									1965	49
									1965 NUL	50
										51
										52
103	0.08	0.20	3790	180	0.88	0.72	9750	1954	1964 CWNG	53
										54
										55
45	0.10	0.35	3650	225	0.95	0.67	11030	1957	1958 CONSIDERED BEYOND	56
									ECONOMIC REACH	57
										58
										59
219	0.03	0.15	2770	135	0.78	0.66	8350	1954	1966 WESTCOAST	60
										61
										62
9	0.17	0.40	930	85	0.89	0.60	2660	1954	1962 TCPL	63
									1968	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
SEDALIA (CONTINUED)									
MANNVILLE	5	0.85	0.05	4		4	1010	4	
SEDGEWICK									
VIKING	3	0.75	0.05	2		2	1000	2	
BASAL MANNVILLE A	19	0.85	0.05	16		16	990	16	2310
MANNVILLE (OTHER)	10	0.85	0.05	8		8	990	8	
SEIU LAKE									
VIKING	8	0.80	0.05	6		6	1000	6	
MANNVILLE	25	0.80	0.05	20	1	19	1000	19	
SEPTEMBER LAKE									
MANNVILLE	12	0.75	0.05	8		8	1030	8	
MANNVILLE ASSOC	1	0.75	0.05	1		1	1030	1	
WABAMUN	2	0.75	0.05	1		1	940	1	
SEXSMITH									
DUNVEGAN	6	0.80	0.05	5	1	4	1000	4	
SIBBALD									
VIKING A	28	0.80	0.05	21	14	7	990	7	9870
VIKING (OTHER)	7	0.80	0.05	6		6	990	6	
BASAL COLORADO A	13	0.80	0.05	10		10	990	10	4210
BANFF	1	0.80	0.05	1		1	1050	1	
SIMONETTE									
CADOTTE	9	0.90	0.05	7		7	1050	7	
CADOMIN A	13	0.85	0.05	10		10	1060	11	1500
WABAMUN A	34	0.85	0.35	19		19	1070	20	250
WABAMUN B	26	0.85	0.35	14		14	1070	15	250
WABAMUN (OTHER)	13	0.85	0.35	7		7	1070	7	
D-3 SOLN	270	0.55	0.40	89	2	87	1020	89	
SMITH COULEE									
BOW ISLAND A	32	0.85	0.05	26	23	3	930	3	
ST. ALBERT-BIG LAKE									
VIKING	1	0.80	0.05	1		1	1070*	1	
VIKING ASSOC	2	0.80	0.05	2		2	1070*	2	
OSTRACOD A	98	0.85	0.05	80	65	15	1070*	16	
BASAL QUARTZ B	26	0.85	0.05	21		21	1070*	22	1060
MANNVILLE (OTHER)	10	0.85	0.05	8		8	1070*	9	
STANDARD									
VIKING A	26	0.80	0.05	20		20	1000	20	5550
STEEP CREEK									
GETHING	6	0.85	0.05	5		5	1020	5	
TRIASSIC	9	0.85	0.10	7		7	1030	7	
PERMO-PENN 26-66-7	17	0.90	0.20	12		12	1030	12	1100
STETTLER									
VIKING	3	0.80	0.05	2		2	1020	2	
D-2 SOLN	21	0.30	0.90	1		1	1130	1	
D-3 SOLN	14	0.55	0.95	1		1	1140	1	
STOLBERG									
RUNDLE A	86	0.90	0.10	70		70	1040	73	1480
ST. PAUL									
MANNVILLE	5	0.75	0.10	4	4	□ 1	1000	□ 1	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968	2
										3
										4
									1956	5
11	0.30	0.20	980	95	0.86	0.64	2940	1954	1968	6
									1956	7
										8
										9
									1966	10
									1963 TCPL	11
										12
										13
									1966 CONSIDERED BEYOND	14
									1966 ECONOMIC REACH	15
									1966	16
										17
										18
									1967 LOCAL UTILITY	19
										20
										21
6	0.22	0.30	1000	90	0.89	0.58	2530	1951	1966 TCPL	22
									1960	23
8	0.15	0.30	1110	90	0.87	0.61	2700	1953	1960	24
									1966	25
										26
										27
									1957	28
17	0.09	0.35	2970	165	0.85	0.66	8110	1960	1968	29
154	0.08	0.15	4950	220	0.87	0.81	11240	1959	1966	30
116	0.08	0.15	4870	220	0.87	0.81	11120	1960	1966	31
										32
									1967	33
							11580	1958	1966 CANADIAN UTILITIES	34
										35
										36
		GIP BASED ON MATERIAL BALANCE					2050	1948	1967 CMG	37
										38
										39
									1965	40
									1957	41
		GIP BASED ON MATERIAL BALANCE					3710	1952	1962 CIGOL	42
33	0.20	0.25	1360	120	0.85	0.67	3800	1952	1964	43
										44
									1964	45
										46
										47
8	0.20	0.30	1290	85	0.84	0.63	4180	1956	1963	48
										49
										50
									1961 CONSIDERED BEYOND	51
									1961 ECONOMIC REACH	52
35	0.06	0.30	4350	240	0.91	0.66	10470	1956	1961	53
										54
										55
									1963 CWNG	56
									1966 CWNG	57
									1966 CWNG	58
										59
										60
122	0.05	0.20	5100	200	0.99	0.64	12730	1957	1958	61
										62
										63
									1966 LOCAL UTILITY	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
STRACHAN									
D-3 A	2060	0.85	0.20	1400		1400	1100	1540	5150
STRATHMORE									
BELLY RIVER	14	0.80	0.05	11	4	7	1000	7	
VIKING	9	0.80	0.05	7		7	1000	7	
RUNDLE	2	0.80	0.05	1		1	1000	1	
STROME									
MANNVILLE	2	0.90	0.05	1		1	1030	1	
STURGEON LAKE									
GETHING	13	0.85	0.05	10		10	1000	10	
GILWOOD	1	0.85	0.15	1		1	1000	1	
STURGEON LAKE SOUTH									
GETHING 19-69-25	21	0.85	0.10	16		16	1000	16	1100
GETHING (OTHER)	23	0.85	0.05	19		19	1000	19	
TRIASSIC ASSOC	3	0.85	0.10	2		2	1180	2	
TRIASSIC SOLN	13	0.65	0.70	3		3	1180	4	
PERMO-PENN	11	0.85	0.05	9		9	1030	9	
D-1	4	0.90	0.20	3	1	2	1070	2	
D-3 ASSOC	10	0.90	0.25	7		7	1080	8	
D-3 SOLN	270	0.55	0.45	83	16	67	1080	72	
SUNDRE									
MANNVILLE	6	0.85	0.10	4		4	1020	4	
MANNVILLE ASSOC	10	0.90	0.10	8		8	1020	8	
RUNDLE A ASSOC	21	0.85	0.15	15		15	1060*	16	1660
RUNDLE A SOLN	59	0.40	0.50	12		12	1060*	13	
RUNDLE SOLN (OTHER)	13	0.60	0.50	4		4	1060*	4	
SUNNYNOOK									
VIKING	1	0.75	0.05	1		1	1020	1	
MANNVILLE	16	0.85	0.05	13		13	1020	13	
SWALWELL									
VIKING	7	0.80	0.05	5		5	1000	5	
PEKISKO A ASSOC	43	0.85	0.05	35		35	1100	39	4000
SWAN HILLS									
GETHING	2	0.90	0.05	1		1	1050	1	
BHL LK A & B SOLN	1090	0.45	0.35	320	23	297	1200*	356	
SWAN HILLS SOUTH									
BHL LK SOLN	570	0.45	0.30	180	16	164	1120*	184	
SYLVAN LAKE									
VIKING	4	0.85	0.05	3		3	1010*	3	
GLAUCONITIC A	210	0.85	0.10	160	34	126	1100*	139	6290
OSTRACOD B	27	0.85	0.10	21	2	19	1100*	21	2230
LOWER MANNVILLE A	34	0.85	0.10	26	7	19	1100*	21	2830
LOWER MANNVILLE C	22	0.85	0.10	17	9	8	1100*	9	2260
LOWER MANNVILLE D	28	0.85	0.10	21	3	18	1100*	20	2620
MANNVILLE (OTHER)	46	0.85	0.10	35	1	34	1100*	37	
MANNVILLE ASSOC	2	0.80	0.10	2		2	1100*	2	
JURASSIC	25	0.85	0.10	19	1	18	1020*	18	
JURASSIC A ASSOC	40	0.80	0.10	29		29	1020*	30	3010
JUR ASSOC (OTHER)	3	0.85	0.10	2		2	1020*	2	
JURASSIC SOLN	23	0.60	0.45	8		8	1100*	9	

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Line	11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESSIBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS
2	290	0.11	0.10	7150	250	1.14	0.74	9430	1967	1969
5										1963 CWNG
6										1963
7										1963
10										1966 LOCAL UTILITY
13										1967 CONSIDERED BEYOND
14										1967 ECONOMIC REACH
17	34	0.15	0.30	1700	115	0.86	0.61	5200	1954	1967
18										1967
19										1967
20										1965
22										1968
23										1967 CANADIAN UTILITIES
24										1961
25								8850	1953	1965 CANADIAN UTILITIES
28										1964
29										1966
30	16	0.10	0.20	3670	200	0.90	0.65	9050	1955	1964
31								9050	1955	1965
33										1965
36										1966
37										1966 TCPL
40										1966
41	32	0.08	0.25	1790	145	0.83	0.69	5300	1963	1966
44										1962
45								8300	1957	1966 NUL
48								7450	1959	1966 NUL
51										1966
52	31	0.13	0.30	2420	155	0.79	0.75	7100	1953	1964 TCPL
53	13	0.17	0.30	2650	160	0.82	0.73	7790	1963	1964 TCPL
54	18	0.13	0.30	2470	160	0.82	0.73	7170	1955	1964 TCPL
56	13	0.15	0.30	2450	160	0.80	0.72	7130	1953	1964 TCPL
57	16	0.13	0.30	2410	155	0.81	0.73	6890	1953	1964 TCPL
58										1964 TCPL
59										1964
60										1965
62	21	0.12	0.30	2500	160	0.83	0.69	7410	1962	1965
63										1966
64										1965

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
1	2	3	4	5	6	7	8	9	10
SYLVAN LAKE (CONTINUED)									
ELKTON-SHUNDA A	25	0.85	0.10	20	9	11	1100*	12	3380
SHUNDA B	24	0.85	0.10	18		18	1100*	20	1790
PEKISKO L	76	0.80	0.10	55	2	53	1100*	58	3220
RUNDLE (OTHER)	29	0.85	0.10	23		23	1100*	25	
RUNDLE ASSOC	17	0.80	0.10	12		12	1100*	13	
RUNDLE SOLN	38	0.60	0.35	15		15	1200*	18	
D-3 A ASSOC	35	0.80	0.10	25**					1800
D-3 SOLN	15	0.65	0.45	5**	3**	27	1020*	28	
TABER SOUTH									
BOW ISLAND A	17	0.70	0.05	11		11	1000	11	12410
BOW ISLAND (OTHER)	11	0.80	0.05	8		8	1000	8	
TANGENT									
PEACE RIVER	12	0.75	0.05	6		6	1010	6	
GETHING	42	0.85	0.05	34		34	1000	34	
TRIASSIC	25	0.85	0.05	20		20	1180	24	
TELFORDVILLE									
MISSISSIPPIAN	11	0.85	0.10	9		9	1110	10	
WABAMUN	7	0.85	0.15	4		4	1090	4	
THORHILD									
MANNVILLE A	12	0.85	0.05	10		10	1000	10	2550
MANNVILLE (OTHER)	1	0.85	0.05	1		1	1000	1	
THREE HILLS CREEK									
BELLY RIVER	8	0.85	0.05	7		7	970	7	
VIKING	8	0.80	0.05	6		6	1000	6	
PEKISKO	190	0.85	0.05	150	23	127	1120*	142	43770
LEDUC	11	0.75	0.15	7		7	1100	8	
TROCHU									
MANNVILLE	14	0.75	0.10	10		10	1030	10	
TURIN									
BOW ISLAND	14	0.80	0.05	10		10	970	10	
MANNVILLE	17	0.90	0.15	13		13	1020	13	
MANNVILLE ASSOC	10	0.85	0.15	7		7	1020	7	
TURNER VALLEY									
RUNDLE ASSOC	1570	0.90	0.70	410	297	113	1110*	125	
RUNDLE SOLN	1400	0.55	0.55	350	285	65	1110*	72	
TWEEDIE									
VIKING	13	0.80	0.05	10	1	9	1000	9	
GRAND RAPIDS A	17	0.80	0.05	13	1	12	1040	12	10430
GLAUCONITIC A	18	0.80	0.05	14	2	12	1040	12	15650
MCMURRAY A	16	0.80	0.05	12		12	1040	12	17760
MANNVILLE (OTHER)	7	0.80	0.05	5		5	1040	5	
TWINING NORTH									
MANNVILLE	6	0.80	0.05	5		5	1100	6	
RUNDLE	1	0.80	0.05	1		1	1110	1	
RUNDLE ASSOC	37	0.80	0.05	28		28	1110	31	4340

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
17	0.08	0.25	2470	160	0.79	0.75	7140	1955	1965 TCPL	2
23	0.10	0.25	2500	160	0.79	0.75	7210	1953	1964	3
										4
36	0.11	0.25	2380	140	0.79	0.74	6920	1963	1966 TCPL	5
									1964	6
									1964	7
									1965	8
41	0.06	0.20	3490	210	0.87	0.74	9400	1961	1964 TCPL	9
										10
									1964 TCPL	11
										12
										13
6	0.20	0.30	540	80	0.94	0.60	2300	1963	1965 CONSIDERED BEYOND	14
									1961 ECONOMIC REACH	15
										16
										17
									1968	18
									1968	19
									1968	20
										21
										22
									1957	23
									1966	24
										25
										26
12	0.25	0.30	740	85	0.91	0.60	2570	1963	1966 LOCAL UTILITY	27
									1964	28
										29
										30
									1963	31
									1963	32
27	0.05	0.35	1720	150	0.85	0.70	5770	1953	1968 TCPL	33
									1963	34
										35
										36
									1968	37
										38
										39
									1968	40
									1968	41
									1968	42
										43
										44
							6000	1936	1953 CWNG AND LOCAL	45
							8390	1936	1953 UTILITY	46
										47
										48
									1968 GREAT CANADIAN OIL	49
									SANDS LIMITED	50
6	0.38	0.30	320	55	0.95	0.56	900	1961	1968 GREAT CANADIAN OIL	51
									SANDS LIMITED	52
										53
7	0.28	0.50	360	60	0.94	0.57	1390	1961	1968 GREAT CANADIAN OIL	54
									SANDS LIMITED	55
6	0.27	0.50	360	60	0.95	0.57	1430	1961	1968 GREAT CANADIAN OIL	56
									SANDS LIMITED	57
									1968 GREAT CANADIAN OIL	58
									SANDS LIMITED	59
										60
										61
									1964	62
									1964	63
36	0.07	0.30	1660	145	0.85	0.68	5370	1961	1964	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
TWINING NORTH (CONTINUED)									
RUNDLE ASSOC (OTHER)	1	0.80	0.05	1		1	1110	1	
RUNDLE SOLN	15	0.60	0.15	8		8	1110	9	
TWO CREEK									
TRIASSIC 11-63-16	12	0.90	0.05	10		10	1090	11	1100
USONA									
MANNVILLE 11-45-27	12	0.90	0.05	10		10	1110	11	470
VERGER									
BOW ISLAND	3	0.75	0.05	2		2	1100	2	
BASAL COLORADO	11	0.80	0.05	9	3	6	1010	6	
MANNVILLE	39	0.75	0.05	28	2	26	1050	27	
PEKISKO	2	0.85	0.05	2		2	1070	2	
VIKING-KINSELLA									
VIKING	960	0.85	0.05	770	422	348	1000	348	40800
WAINWRIGHT	41	0.80	0.05	31	4	27	1000	27	6750
MANNVILLE (OTHER)	40	0.80	0.05	30	15	15	1000	15	
D-2	18	0.80	0.05	14	5	9	990*	9	
D-3	1	0.85	0.05	1	1	¤ 1	990*	¤ 1	
VIRGINIA HILLS									
MANNVILLE	9	0.90	0.05	8		8	1040	8	
BELLOY A ASSOC	20	0.85	0.10	15		15	1060	16	3200
BHL LK'SOLN	220	0.40	0.40	54	7	47	1070*	50	
SLAVE POINT	4	0.80	0.20	2		2	1070	2	
VULCAN									
BASAL MANNVILLE A	15	0.85	0.15	11	1	10	1050	11	2320
MANNVILLE (OTHER)	5	0.85	0.15	4		4	1050	4	
TURNER VALLEY A	19	0.80	0.20	13	1	12	1050	13	2440
TV (OTHER)	4	0.80	0.20	2		2	1050	2	
WAINWRIGHT									
VIKING	5	0.80	0.05	4		4	980	4	
MANNVILLE	18	0.85	0.05	14		14	940	13	
MANNVILLE ASSOC	8	0.75	0.05	5		5	940	5	
WASKAHIGAN									
CARDIUM	4	0.80	0.05	3		3	1060	3	
DUNVEGAN A	125	0.80	0.05	90		90	1110	100	26980
CADOTTE	5	0.85	0.05	4		4	1070	4	
WATERTON									
RUNDLE A	54	0.80	0.30	32	5	27	1040*	28	
RUNDLE C	350	0.75	0.45	150	11	139	1040*	145	13390
RUNDLE D & E	470	0.80	0.50	190	46	144	1040*	150	
RUNDLE (OTHER)	7	0.85	0.30	4		4	1040*	4	
RUNDLE-WABAMUN A	3080	0.85	0.35	1700	149	1551	1020	1582	
WABAMUN B	36	0.80	0.20	25	11	14	1020	14	
WABAMUN 31-6-3	40	0.85	0.15	29		29	1020	30	2000
WATTS									
VIKING	3	0.80	0.05	2	2	¤ 1	1030*	¤ 1	
MISSISSIPPIAN	1	0.80	0.05	1		1	1070	1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1964	2
										3
									1965	4
										5
										6
12	0.20	0.30	2200	170	0.88	0.66	6590	1956	1956 CONSIDERED BEYOND	7
									ECONOMIC REACH	8
										9
										10
32	0.22	0.30	1660	140	0.84	0.71	5110	1954	1955 CONSIDERED BEYOND	11
									ECONOMIC REACH	12
										13
										14
									1964 TCPL	15
									1965 TCPL	16
									1968 TCPL	17
									1964 TCPL	18
										19
										20
5	0.23	0.20	810	75	0.90	0.60	2080	1914	1966 NUL AND LOCAL	21
									UTILITY	22
13	0.26	0.25	740	85	0.91	0.59	2330	1951	1966 NUL	23
									1966 NUL	24
										25
									1966 NUL	26
									1961 NUL	27
										28
										29
									1962	30
10	0.15	0.30	1950	155	0.86	0.69	6150	1961	1962	31
							9290	1957	1966 NUL	32
									1962	33
										34
										35
9	0.15	0.35	2320	125	0.85	0.76	5880	1956	1968 TCPL	36
									1968	37
13	0.10	0.40	2440	145	0.82	0.76	5940	1960	1966 TCPL	38
									1966	39
										40
										41
									1959 LOCAL UTILITY	42
									1960 LOCAL UTILITY	43
									1968	44
										45
										46
									1967	47
12	0.16	0.45	1490	145	0.85	0.67	5080	1959	1969	48
									1967	49
										50
										51
		GIP BASED ON MATERIAL BALANCE					9406	1960	1968 A&S	52
56	0.05	0.25	5200	190	1.00	0.94	11600	1957	1968 A&S	53
		GIP BASED ON MATERIAL BALANCE					10700	1957	1968 A&S	54
									1964 A&S	55
										56
		GIP BASED ON MATERIAL BALANCE					10350	1959	1968	57
		GIP BASED ON MATERIAL BALANCE					13400	1958	1968 A&S	58
58	0.05	0.20	4020	205	0.91	0.66	12170	1964	1966	59
										60
										61
									1960 LOCAL UTILITY	62
									1955	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WAYNE-ROSEDALE									
BELLY RIVER	8	0.80	0.05	6	1	5	1000	5	
VIKING A	160	0.85	0.05	130	29	101	1090*	110	49870
VIKING B	37	0.80	0.05	28	4	24	1090*	26	9940
VIKING (OTHER)	29	0.85	0.05	23	1	22	1090*	24	
GLAUCONITIC A	150	0.85	0.05	120	28	92	1120	103	19440
MANNVILLE (OTHER)	64	0.85	0.05	52	12	40	1120	45	
MANNVILLE ASSOC	3	0.85	0.05	2	2	□ 1	1120	□ 1	
WEST DRUMHELLER									
MANNVILLE	4	0.85	0.05	3		3	1100	3	
RUNDLE	1	0.80	0.05	1		1	1040	1	
D-2 ASSOC	5	0.90	0.15	4		4	1090	4	
WESTEROSE									
VIKING	3	0.80	0.05	2		2	1000	2	
MANNVILLE	7	0.80	0.05	5		5	1020	5	
NISKU	2	0.90	0.05	1		1	1050	1	
D-3 ASSOC	130	0.90	0.20	90	-7	97	1050*	102	1220
D-3 SOLN	150	0.70	0.20	83	10	73	1050*	77	
WESTEROSE SOUTH									
WABAMUN	8	0.90	0.25	6		6	1090	7	
D-3 A	1850	0.90	0.20	1350	415	935	1060*	991	11790
WESTLOCK									
VIKING	320	0.80	0.05	250	67	183	1060	194	75270
VIKING (OTHER)	8	0.80	0.05	6		6	1060	6	
MANNVILLE	4	0.85	0.05	3		3	1100*	3	
WEST PRAIRIE									
CADOTTE 18-72-17	17	0.90	0.05	15		15	1040	16	1100
BLUESKY	6	0.90	0.05	5		5	990	5	
WHISKEY									
RUNDLE A	157	0.85	0.25	100		100	1110*	111	
WHITECOURT									
BELLY RIVER	2	0.85	0.05	1		1	1000	1	
VIKING	1	0.75	0.05	1		1	1050	1	
MANNVILLE	14	0.80	0.10	10		10	1050	11	
JURASSIC E	55	0.85	0.10	42		42	1070	45	5130
JURASSIC	26	0.80	0.10	18		18	1070	19	
PEKISKO C	13	0.85	0.10	10		10	1130	11	830
PEKISKO	35	0.85	0.10	26		26	1130	29	
WHITELAW									
BLUESKY	2	0.80	0.05	1		1	1020	1	
BLUESKY A-GETHING A	14	0.85	0.05	12	5	7	1020	7	2600
GETHING B	13	0.85	0.05	11	1	10	1020	10	3720
TRIASSIC A	21	0.85	0.05	16		16	1090	17	5680
TRIASSIC (OTHER)	10	0.90	0.05	9		9	1090	10	
WILDCAT HILLS									
RUNDLE A	900	0.80	0.17	600	146	454	1050*	477	9630
WILDHORSE CREEK									
RUNDLE A	160	0.85	0.20	110		110	1010	111	1960

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1961 CWNG	2
6	0.20	0.30	1170	110	0.87	0.64	3710	1953	1965 TCPL	3
9	0.16	0.30	1170	110	0.87	0.64	3950	1954	1963 TCPL	4
									1966 CWNG & LOCAL UTILITY	5
										6
13	0.18	0.30	1430	115	0.82	0.66	4400	1953	1966 CWNG & LOCAL UTILITY	7
									1961 CWNG & LOCAL UTILITY	8
									1962	9
										10
										11
									1954	12
									1956	13
									1968	14
										15
										16
									1961	17
									1953	18
									1959	19
200	0.08	0.15	2520	180	0.83	0.71	6990	1952	1959	20
										21
							7230	1952	1966 TCPL	22
										23
										24
									1961	25
249	0.09	0.10	2750	180	0.81	0.81	7640	1953	1969 TCPL	26
										27
										28
13	0.19	0.35	840	95	0.90	0.58	2600	1949	1964 CIGOL & LOCAL	29
									UTILITY	30
									1964	31
									1962	32
										33
										34
35	0.20	0.30	990	85	0.87	0.68	2580	1956	1956 CONSIDERED BEYOND	35
									1956 ECONOMIC REACH	36
										37
										38
									1969	39
										40
										41
									1963	42
									1958	43
									1963	44
23	0.18	0.50	1850	140	0.84	0.64	5070	1962	1969	45
										46
									1968	47
48	0.09	0.45	1840	145	0.85	0.64	5080	1968	1968	48
									1968	49
										50
										51
									1961 LOCAL UTILITY	52
14	0.21	0.45	1110	75	0.87	0.57	2900	1950	1966 LOCAL UTILITY	53
6	0.20	0.25	1150	75	0.86	0.57	2180	1959	1966 LOCAL UTILITY	54
5	0.21	0.30	1430	105	0.82	0.58	3240	1951	1966	55
										56
									1957	57
										58
										59
198	0.05	0.15	3910	185	0.91	0.70	9880	1958	1967 A&S	60
										61
										62
123	0.08	0.15	3200	140	0.85	0.68	7380	1960	1968	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WILDMERE									
MANNVILLE	37	0.80	0.05	28	10	18	960*	17	
WILDUNN CREEK									
VIKING A	19	0.60	0.05	11		11	1010	11	8810
VIKING B	16	0.70	0.05	11	4	7	1010	7	4080
WILLESDEN GREEN									
BELLY RIVER E	34	0.85	0.10	26		26	1000	26	3790
BELLY RIVER (OTHER)	23	0.80	0.05	17		17	1000	17	
CARDIUM	12	0.80	0.05	9		9	1040*	9	
CARDIUM SOLN	440	0.40	0.55	83	7	76	1040*	79	
MANNVILLE	29	0.85	0.10	22		22	1100	24	
MANNVILLE ASSOC	2	0.75	0.15	1		1	1100	1	
JURASSIC	4	0.75	0.05	3		3	1080	3	
MISSISSIPPIAN	3	0.80	0.05	2		2	1100	2	
WILLINGDON									
VIKING	3	0.75	0.05	2		2	980	2	
MANNVILLE	16	0.75	0.05	12	3	9	990	9	
D-3	12	0.80	0.05	9	8	1	1000*	1	
WILSON CREEK									
PEKISKO A	51	0.85	0.10	39	3	36	1120*	40	7900
BANFF A	15	0.85	0.15	11		11	1120*	12	1100
WIMBORNE									
VIKING	2	0.75	0.05	1		1	1020	1	
RUNDLE	2	0.90	0.10	1		1	1100	1	
D-2	1	0.85	0.15	1		1	1160	1	
D-2 ASSOC	2	0.80	0.15	2		2	1160	2	
D-3 A ASSOC	360	0.70	0.25	190**					15080
D-3 A SOLN	110	0.95	0.25	3**	47**	146	1000*	146	
WINDFALL									
VIKING A	17	0.75	0.05	12		12	1030	12	8990
RUNDLE	5	0.85	0.05	4	2	2	1040	2	
D-3	3	0.90	0.35	2		2	1080*	2	
D-3 A ASSOC	710	0.80	0.30	400**					11600
D-3 A SOLN	230	0.70	0.35	110**	64**	446	1080*	482	
WINNIFRED									
BOW ISLAND A	19	0.85	0.05	16		16	1000	16	22560
BOW ISLAND (OTHER)	1	0.80	0.05	1		1	1000	1	
WINTERING HILLS									
BELLY RIVER	2	0.75	0.05	1		1	1000	1	
VIKING D	12	0.90	0.05	10		10	1010	10	1100
VIKING (OTHER)	18	0.85	0.05	14	2	12	1010	12	
VIKING ASSOC	9	0.75	0.05	7		7	1010	7	
MANNVILLE	26	0.80	0.10	20		20	1090	22	
LOWER MANN E ASSOC	17	0.75	0.10	12	1	11	1090	12	2850
MANN ASSOC (OTHER)	5	0.80	0.05	4		4	1090	4	
RUNDLE	2	0.80	0.05	1		1	1090	1	
WIZARD LAKE									
BELLY RIVER	2	0.75	0.05	1		1	1050	1	
VIKING	1	0.85	0.05	1		1	1070	1	
MANNVILLE	3	0.85	0.05	2	2	□ 1	1120	□ 1	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1953 NUL	2
										3
										4
4	0.25	0.40	1110	90	0.86	0.61	3030	1952	1967	5
7	0.25	0.40	1130	90	0.87	0.59	3090	1952	1967 TCPL	6
										7
										8
16	0.15	0.25	1600	145	0.82	0.70	5050	1967	1967	9
									1965	10
									1961	11
							6190	1954	1967 A&S	12
										13
									1962	14
									1965	15
									1956	16
									1956	17
										18
										19
									1961 WESTERN MINERALS AND	20
									1961 LOCAL UTILITY	21
									1965 WESTERN MINERALS	22
										23
										24
19	0.06	0.25	2800	190	0.87	0.68	7040	1960	1966 A&S	25
37	0.06	0.25	2800	195	0.87	0.70	7290	1961	1966	26
										27
										28
									1956	29
									1961	30
									1959	31
									1959	32
										33
41	0.08	0.10	3010	175	0.83	0.78	7480	1954	1969 TCPL	34
							7490	1956	1969 TCPL	35
										36
										37
6	0.08	0.20	1570	145	0.87	0.63	5140	1955	1963	38
									1961 A&S	39
									1961	40
116	0.06	0.15	3790	220	0.83	0.81	9050	1955	1967 A&S PRESSURE MAIN-	41
										42
							9100	1957	1966 A&S TAINED WITH PINE	43
									CK & PINE NW GAS	44
										45
										46
4	0.20	0.40	730	85	0.92	0.59	2080	1963	1966 LOCAL UTILITY	47
									1969	48
										49
										50
									1963	51
19	0.20	0.30	1280	90	0.86	0.65	3130	1955	1965	52
									1966 TCPL	53
									1965	54
										55
									1968	56
13	0.17	0.35	1410	105	0.80	0.70	4110	1966	1968	57
									1966	58
									1963	59
										60
										61
									1966	62
									1960	63
									1959 NUL	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WIZARD LAKE (CONTINUED)									
MANNVILLE ASSOC	11	0.80	0.15	8	8	□ 1	1120	□ 1	
D-2 ASSOC	1	0.85	0.20	1		1	1180	1	
D-3 A SOLN	230	0.65	0.25	110	24	86	1250	108	
WOKING									
PEACE RIVER	5	0.90	0.05	4		4	1040	4	
SPIRIT RIVER	3	0.80	0.05	2		2	1040	2	
BLUESKY	4	0.80	0.05	3	1	2	1040	2	
PERMO-PENN	2	0.80	0.05	2		2	1060	2	
KISKATINAW	3	0.75	0.05	2		2	1070	2	
WOOD RIVER									
MANNVILLE	31	0.85	0.10	24	10	14	1100	15	
WORSLEY									
D-3 A	40	0.85	0.05	32	18	14	950*	13	3380
D-3 B	90	0.85	0.05	72	17	55	950*	52	3720
D-3 D	39	0.85	0.10	30	21	9	950*	9	1000
D-3 E	16	0.85	0.05	13	3	10	950*	10	500
D-3 G	65	0.85	0.05	53	20	33	950*	31	3700
D-3 (OTHER)	4	0.85	0.05	3	1	2	950*	2	
D-3 ASSOC	1	0.80	0.05	1		1	950*	1	
YEKAU LAKE									
VIKING	8	0.80	0.02	7	2	5	1070	5	
ZAMA									
SLAVE POINT	73	0.90	0.10	60		60	1050*	63	
SULPHUR POINT	220	0.85	0.15	160		160	1050*	168	
SULPHUR POINT ASSOC	5	0.85	0.15	3		3	1050*	3	
SULPHUR POINT SOLN	6	0.70	0.30	3		3	1100*	3	
MUSKEG SOLN	26	0.70	0.25	13		13	1100*	14	
KEG RIVER	14	0.90	0.20	10		10	1150*	12	
KEG RIVER ASSOC	6	0.85	0.55	3		3	1150*	3	
KEG RIVER SOLN	220	0.70	0.25	110		110	1200*	132	
SUB TOTAL				52016	8887	43129		45489	
OTHER RESERVES									
LESS THAN 10 BCF				767		767		805	
CONFIDENTIAL POOLS				444		444		466	
TOTAL RESERVES MAY 31,1969				53227	8887	44340		46760	
TOTAL RESERVES WITHIN ECONOMIC REACH				50604	8887	41717		43892	
TOTAL RESERVES BEYOND ECONOMIC REACH				2623		2623		2868	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1959 NUL
									1968
							6460	1951	1966 NUL
									1961
									1961
									1961 LOCAL UTILITY
									1961
									1961
									1961 TCPL
28	0.06	0.20	3310	185	0.90	0.68	7420	1960	1966 WESTCOAST
50	0.07	0.20	3240	180	0.90	0.65	7240	1960	1966 WESTCOAST
60	0.10	0.20	3090	180	0.89	0.73	7660	1961	1966 WESTCOAST
42	0.11	0.20	3060	170	0.91	0.67	7030	1966	1966 WESTCOAST
42	0.06	0.20	3300	180	0.91	0.64	7280	1959	1966 WESTCOAST
									1966 WESTCOAST
									1965
									1969 INJECTED INTO LEDUC-WOODBEND
									1967 CONSIDERED BEYOND
									1967 ECONOMIC REACH
									1967
									1968
									1968
									1967
									1967
									1968

APPENDIX B

THE GROWTH TREND OF RESERVES OF GAS IN ALBERTA AND THE FUTURE RESERVES TO BE CONSIDERED

The reserves considered in this appendix in determining the trends in the growth of reserves are the initial marketable reserves without adjustment for heating value.

Growth of Reserves

The Board in its report and decision respecting the procedures followed in determining gas surplus to the needs of the Province, OGCB 69-D[1], stated that in future it would review the growth rate over the most recent 10-year period to determine the amount of future reserve growth to be included in calculating the future surplus. Accordingly, it has done so in this report.

(1) Views of Trans-Canada

Trans-Canada did not present a detailed study of the trends in the growth of gas reserves in the Province. It estimated the initial marketable gas reserves in the Province, as of February 28, 1969, to be 53.2 trillion cubic feet. This estimate was made by adding the 2.6 trillion cubic feet increase which it estimated had occurred in the fields that will produce under contract to Trans-Canada and in certain other fields and areas, to the Board's estimate of the initial marketable reserves of the Province as of August 31, 1968.

Trans-Canada determined the average growth rate over the last two years by comparing its estimate of the initial marketable

(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

gas reserves at February 28, 1969, of 53.2 trillion cubic feet with the Board's estimate of initial marketable gas reserves as of December 31, 1966, of 44.4 trillion cubic feet. On this basis it concluded that the two-year growth rate was 8.2 trillion cubic feet or 4.1 trillion cubic feet per year.

The applicant estimated the average long term growth rate from its estimate of the initial marketable gas reserves at February 28, 1969, and the Board's estimate of the initial marketable gas reserves as of June 30, 1955, of 15.9 trillion cubic feet (adjusted to 14.65 psia). It thus determined the long term growth rate to be 2.7 trillion cubic feet per year.

(2) Views of the Board

The Board, in OGCB Report 69-18[2] reviewed in detail the long term trend in the growth of initial marketable gas reserves in the Province to December 31, 1968, and concluded that the long term growth rate was 2.5 trillion cubic feet per year. The long term growth of initial marketable gas reserves due to new discoveries and to appreciation of previous discoveries has continued to average some 2.5 trillion cubic feet per year determined on the basis used in previous reports.

The Board estimated the initial marketable gas reserves as of May 31, 1969, to be some 53.2 trillion cubic feet as shown in Appendix A. At September 30, 1959[3] the Board estimated the

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(2) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1968.

(3) Report to the Lieutenant Governor in Council with Respect to the Applications under The Gas Resources Preservation Act, 1956 of: Alberta and Southern Gas Co. Ltd., Saskatchewan Power Corporation, Trans-Canada Pipe Lines Limited, Westcoast Transmission Company Limited. December, 1959.

initial marketable gas reserves to be 28.0 trillion cubic feet. The initial marketable reserves have thus increased by 25.2 trillion cubic feet during the period or at the rate of 2.6 trillion cubic feet per year. Using the initial marketable gas reserves estimated in OGCB Report 64-8[(4)] as 36.7 trillion cubic feet at December 31, 1963, and in OGCB Report 67-18[(5)] as 44.4 trillion cubic feet at December 31, 1966, the annual growth rates over the last five years and over the last two years have averaged 3.0 trillion cubic feet and 3.6 trillion cubic feet respectively. Having regard for all relevant factors the Board considers it appropriate to adopt an average growth rate of 2.6 trillion cubic feet per year in estimating the growth of initial gas reserves over the next four or five years.

Ultimate Reserves

Neither Trans-Canada nor any of the interveners submitted new evidence respecting the ultimate gas reserves of the Province. However, the Alberta Division of the Canadian Petroleum Association included an estimate of 120 trillion cubic feet for the ultimate reserves of the Province along with supporting data in its submission to the hearing of June 17, 1969, reported on in OGCB 69-D. The Canadian Petroleum Association's estimate of the ultimate reserves is close to that of the Board and having in mind the Board's wish to be conservative in this regard the Board

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(4) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1963.

(5) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1966.

will continue to use 100 trillion cubic feet as its estimate of the ultimate reserves for the present. It plans to consider this matter in more detail in its 1969 year end report on the Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur of the Province.

Future Reserves to be Considered

(1) Views of Trans-Canada

The Board decision, respecting the application of the Alberta Division of the Canadian Petroleum Association, considered at the hearing which began June 17, 1969, for reconsideration of the policies and procedures of the Board for considering applications under The Gas Resources Preservation Act, 1956, was not issued until after the hearing of the Trans-Canada application. Trans-Canada applied the previous policy of the Board of normally using two years of growth at the long term rate in determining the future reserves to be considered in assessing the provincial surplus. Accordingly, Trans-Canada used 5.4 trillion cubic feet of future reserves based on two years growth at 2.7 trillion cubic feet per year.

(2) Views of the Board

The Board has applied the new policy described in OGCB 69-D in determining the future reserves to be considered. In the report the Board adopted a method proposed by the Canadian Petroleum Association whereby the future growth rate of gas reserves is projected principally on the basis of the growth experienced during the previous 10 years and the number of years

of growth to be considered is determined by the following formula:

$$T_G = \frac{R_{POT} - R_{EST}}{10}$$

where T_G = Years of growth of gas reserves,

R_{POT} = Potential initial marketable reserves of the Province, trillions of cubic feet, and

R_{EST} = Established initial marketable reserves at the time of application of the formula, trillions of cubic feet.

Using the potential initial marketable reserves of 100 trillion cubic feet and established initial marketable reserves of 53.2 trillion cubic feet determined in this report and the formula, 4.5 years of growth of gas reserves can be used at this time.

The Board is confident that the growth rate, over the last 10 years, of 2.6 trillion cubic feet per year will continue for four and one-half years into the future so that future reserves of 11.7 trillion cubic feet can be relied upon.

APPENDIX C

ALBERTA GAS REQUIREMENTS AND PERMIT COMMITMENTS

Trans-Canada did not present its own forecast of Alberta's 30-year requirements, but rather relied upon updating the Board forecast published in OGCB Report 69-A[1] to relate to the period March 1, 1969 to March 1, 1999.

The Utility Companies did not revise their previous forecast other than to adjust it to a level of 12.9 trillion cubic feet to be applicable to the period 1969 to 1998 inclusive.

In view of the Board's decision in the report OGCB 69-D[2] to hold a requirements hearing in 1970, the Board has not prepared a new forecast of Alberta requirements at this time. Rather, the Board has confined its review to the 'other' industrial requirements projection and has adjusted its previous forecast to apply to the 30-year period commencing June 1, 1969. Details of the review and the adjustment are given below.

(1) Other Industrial Requirements

'Other' industrial requirements relate to gas shrinkage and fuel consumption at the Pacific Empress plant, the Cochrane plant and the Edmonton Liquid Gas plant and consumption by the Alberta Gas Trunk Line. A review of this category arose from the Board's decision to assess commitments for removal from the Province on the basis of the heating value of the gas leaving

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(1) In the Matter of an Application of Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. February, 1969.

(2) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

the Province rather than the average heating value at the fields named in the permits, and to improve the recognition of heating value considerations in the shrinkage calculations. The review showed that substantial changes to the Board's previous forecast shown in OGCB Report 68-A[3] for the requirements of Pacific's Empress plant and the Cochrane Gas plant of Alberta Natural Gas Company was necessary. The requirements are now estimated to total some 1,300 billion cubic feet over the 30-year period 1969 to 1998. This total is some 500 billion cubic feet more than the amount under the Board's 1968 assessment corresponding to the same period. The Board also believes allowance should be made for the shrinkage and fuel requirements of the proposed Empress plant of Dome Petroleum Limited and Trans-Canada Grid of Alberta, Ltd. The Board's assessment of these requirements amounts to some 220 billion cubic feet over the 30-year period. After inclusion of all changes, 'other' industrial requirement now total some 1,520 billion cubic feet, an increase of 710 billion cubic feet over the Board's previous estimate.

(2) Adjustments to the 30-year Period commencing June 1, 1969

Table C-1 summarizes the forecast of Alberta gas requirements for the period January 1, 1969 to December 31, 1998. The adjustment to the June 1st commencement date is shown in the Table below:

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(3) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

	Bcf
Alberta Requirements January 1, 1969 to December 31, 1998 as per Table C-1	15,538
less Estimated Consumption January to May, 1969 inclusive	137
plus Forecast Consumption January to May, 1999 inclusive	330
Alberta Requirements June 1, 1969 to May 31, 1999	15,731

Thus, the Board estimates Alberta's requirements for gas for the period June 1, 1969 to May 31, 1999 to be 15,731 billion cubic feet of 1000 Btu gas.

Permit Commitments

The present permit commitments and the maximum daily authorized withdrawal rates relate to the 27 permits issued and listed in Table C-2. At May 31, 1969, initial permit volume totalled some 31.7 trillion cubic feet of gas. At this date approximately 5.8 trillion cubic feet or 18 per cent of initial permit volumes have been removed from the Province. The principal adjustments in permit commitments from the level shown in Table C-2 of OGCB Report 68-A relate to the volume authorized for removal from the Province by Trans-Canada and Alberta and Southern. These adjustments are contained in Permit No. TC 68-8, issued on November 14, 1968 and Permit No. AS 69-5 issued on March 25, 1969.

TABLE C-1

Summary of Forecast of Alberta Gas Requirements for Period January 1, 1969 to December 31, 1998 (Billions of Cubic Feet of 1,000 Btu Gas)

	Utility Companies 1966(1)	Revised Board 1966
Domestic		
1969 Annual	56.0	55.9
1998	115.5	126.5
30-year Total	2,511.6	2,659.6
Commercial		
1969 Annual	44.7	43.7
1998 Annual	93.0	105.7
30-year Total	2,013.2	2,174.7
Industrial & Contingency(2)		
1969 Annual	166.2	171.6
1998 Annual	429.2	488.2
30-year Total	9,896.4	10,703.2
Total		
1969 Annual	266.9	271.2
1998 Annual	637.7	720.4
30-year Total	14,421.2	15,537.5
Equivalent Average Annual Growth Rate to Achieve Terminal Year (%)	3.0	3.4
Equivalent Average Annual Growth Rate to Achieve 30-year Total (%)	3.8	4.1

(1) Industrial and Total numbers adjusted to include Board's revised estimate of 'other' industrial consumption.

(2) If the requested increase in permit volumes of gas be granted, 'other' industrial requirements will increase by 130 billion cubic feet over the 30-year period.

TABLE C-2

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
AS 69-5	ALBERTA AND SOUTHERN GAS CO. LTD.	1,270.0	416.0	9,422.0	1,388.6	8,033.4
	BELLOY, BERLAND RIVER, BIGORAY, BIGSTONE, BRAZEAU RIVER, CAROLINE, CARSON CREEK, CARSON CREEK NORTH, CROSSFIELD (RUNDLE A POOL), EAGLESHAM, FERRIER (VIKING A AND CARDIUM B POOLS), FOX CREEK, GOLD CREEK, HARMATTAN-ELKTON (D-3A POOL), HOMEGLEN-RIMBEY, HUNTER VALLEY, JUDY CREEK, KAYBOB, KAYBOB SOUTH (VIKING A. CADOMIN A, CADOMIN B, CADOMIN C, CADOMIN D AND TRIASSIC A POOLS), MARLBORO, MINNEHIK-BUCK LAKE, OPEN CREEK, PEMBINA (LOBSTICK GLAUCONITIC A, LOBSTICK GLAUCONITIC C, GLAUCONITIC D, LOBSTICK OSTRACOD A, LOBSTICK OSTRACOD B AND PEKISKO B POOLS, PINE CREEK, PINE NORTH-WEST, SIMONETTE, STURGEON LAKE SOUTH, SUNDRE, SWAN HILLS, SWAN HILLS SOUTH, SYLVAN LAKE, TANGENT, VIRGINIA HILLS, WASKAHIGAN, WATERTON, WESTEROSE SOUTH, WESTWARD HO, WILDCAT HILLS, WILDHORSE CREEK, WILLESDEN GREEN, WILSON CREEK, WINDFALL.					
CD 63-1	CANADIAN DELHI OIL LTD. - MEDICINE HAT	4.3	.57	[illegible].3	[illegible]	28.2

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSI AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT		PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
CM 54-1 AND CM 61-2	CANADIAN-MONTANA PIPELINE COMPANY						
	ADEN, BLACK BUTTE, COMREY, KNAPPEN, MANYBERRIES, PAKOWKI LAKE, PENDENT D'OREILLE, SMITH COULEE.		100.0	20.0	498.0 (1)	249.1	248.9
CP 63-1	CANADIAN PACIFIC OIL AND GAS LIMITED	- MEDICINE HAT	0.1	0.0365	0.750	0.126	0.624
BH 61-1	DELTA GAS & TRANSMISSION LTD						
BS 61-1	BAILEY SELBURN OIL AND GAS LTD						
CS 61-1	THE CALIFORNIA STANDARD COMPANY						
COG 61-1	CHARTER OIL AND GAS LTD	MEDICINE HAT	9.5	3.5	71.0	-	71.0
SEL 61-1	SELBAY EXPLORATION LTD						
JMW 61-1	J MERRIL WRIGHT, JR						
CEL 61-1	CROWFOOT EXPLORATION LTD						
CMM 61-1	IMPERIAL OIL DEVELOPMENT LIMITED						
MOG 61-1	MIC MAC OILS (1963) LTD.	MEDICINE HAT	8.3	3.0	62.0	10.2	51.8
ROC 61-1	RICHFIELD OIL CORPORATION						
ROC 65-2	ATLANTIC RICHFIELD COMPANY	- MEDICINE HAT	0.26	0.088	2.0	0.2	1.8
HB 63-1	HUDSON'S BAY OIL AND GAS COMPANY LIMITED	MEDICINE HAT	1.02	0.372	7.65	0.57	7.08
SPC 57-1	MANY ISLAND PIPE LINES LTD	- MEDICINE HAT	135.5	44.5	609.4	204.3	405.1
MO 66-1	MURPHY OIL COMPANY LTD	- RED COULEE	0.6	-	0.5	-	0.5
NSU 64-1	THE BRITISH AMERICAN OIL COMPANY LIMITED						
	ROYALITE OIL COMPANY LIMITED	- ANTELOPE AND ESTHER	11.4	4.2	40.0	10.8	29.2
	SUN OIL COMPANY						
	UNITED CANSO OIL & GAS LTD						

(1) TOTAL INITIAL MARKETABLE GAS IN THE FIELDS SHOWN.

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	PEACE RIVER TRANSMISSION COMPANY LIMITED – POUCE COUPE	6.0	0.6	13.0	12.5	20.2
	PEACE RIVER TRANSMISSION COMPANY LIMITED – POUCE COUPE SOUTH	6.9	0.98	19.7		
B 68-1	PATRICK T. BUCKLEY – VANALTA NO. 4 WELL	1.0 MMCF PER MONTH	0.005	-	0.06	-
PG 64-1	TRANS-CANADA PIPE LINES LIMITED – HALLIDAY, RICHDALE AND WILDUNN CREEK	10.0	3.6	45.0	5.4	39.6
TC 68-8	TRANS-CANADA PIPE LINES LIMITED	2,715.0	860.0	19,200.0	3,233.2	15,966.8

ALDERSON, AMISK, ARMADA, ATLEE-BUFFALO, BASHAW, BASSANO, BELLIS, BERRY, BIG BEND, BINDLOSS, BLACK DIAMOND, BLUERIDGE, BOYLE, BRAZEAU RIVER, BRUCE, BURNT TIMBER, CAROLINE (VIKING A, VIKING E, AND BASAL MANNVILLE A POOLS), CARSTAIRS, CASSILS, CASTOR, CESSFORD, CHESTERMERE, CHIGWELL, CONNORSVILLE, COUNTESS, CRAIGEND, CROSSFIELD, CROSSFIELD EAST, DRUMHELLER, EDSON, ENCHANT, EQUITY, ERSKINE, FENN WEST FERRIER, FIGURE LAKE, FLAT, GARRINGTON (MANNVILLE A AND LEDUC A POOLS), GHOST PINE, GILBY, GOODWIN, GREEN-COURT, HACKETT, HAMILTON LAKE, HARMATTAN EAST, HARMATTAN-ELKTON (RUNDLE A POOL) HOMEGLEN-RIMBEY, HUGHENDEN, HUNTER VALLEY, HUSSAR, INNISFAIL, JARROW,

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	JUMPING POUND WEST, KILLAM, LATHOM, LECKIE, LITTLE BOW, LONE PINE CREEK, LONG COULEE, LOOKOUT BUTTE, MALMO, MARTEN HILLS, MCMULLEN, MEDICINE HAT, MEDICINE RIVER, MITSUE, NEVIS, NEWELL, NEW NORWAY, OLDS, OYEN, PELICAN, PINCHER CREEK, PREVO, PRINCESS, PROVOST, QUIRK CREEK, RAINIER, RETLAW, RICH, ROWLEY, SCANDIA, SEDALIA, SEDGEWICK, SEIU LAKE, SIBBALD, STANDARD, SUNDRE, (BASAL MANNVILLE A AND BASAL MANNVILLE B POOLS), SUNNYNOOK, SWALWELL, SYLVAN LAKE, THREE HILLS CREEK, TROCHU, TURIN, TWINING NORTH, VERGER, VULCAN, WAYNE-ROSEDALE, WESTEROSE, WESTEROSE SOUTH, WHITECOURT, WILDHORSE CREEK, WIMBORNE, WINTERING HILLS, WOOD RIVER.					
WC 52-1	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.					
	BRAEBURN, GORDONDALE, POUCE COUPE, POUCE COUPE SOUTH	125.0	35.0	388.0	245.3	142.7
WC 59-3	WESTCOAST TRANSMISSION COMPANY LTD					
	CROSSFIELD (CALGARY BASAL QUARTZ, CALGARY RUNDLE, AND CALGARY WABAMUN POOL, IRRICANA, AND SAVANNA CREEK)	162.2	53.1	1,081.2	336.4	744.8
WC 61-4	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LIMITED					
	BOUNDARY LAKE SOUTH	VOLUMES NOT TO EXCEED THOSE AUTHORIZED IN PERMIT NO. WC 52-1				

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWAN TO MAY 31, 1968 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
WC 62-5	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.					
	WORSLEY	53.3	16.0	220.0	79.7	140.3
		4,620.38	1,467.9515	31,712.50	5,780.556	25,932.004

APPENDIX D

THE MEETING OF ALBERTA'S REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

(1) Views of Trans-Canada

Trans-Canada did not present detailed evidence to show how Alberta's 30-year requirements for gas might be met but did estimate the surplus of gas in the Province employing the method in use by the Board at the time the application was made. The estimates of reserves and requirements were made by updating those most recently published by the Board. Since Trans-Canada did not have access to information on recent developments and new discoveries other than those where it had contracted for gas, it made a somewhat arbitrary estimate of the growth in gas reserves. Trans-Canada submitted that the long term trend in the growth of reservers was 2.7 trillion cubic feet per year.

Trans-Canada submitted a detailed table included here as Table D-5 whereby it showed that the contractable gas reserves at February 28, 1969 exceeded the contractable requirements by 3.1 trillion cubic feet. It calculated that the future surplus at February 28, 1969, was 1.2 trillion cubic feet and that an overall surplus of 4.3 trillion cubic feet resulted after taking account of the contractable surplus of 3.1 trillion cubic feet. It determined the quantities shown in the table in a manner similar to that used by the Board, but included as future reserves that gas provided earlier in the table to meet the terminal year peak day requirement in permits. Other differences resulted from

varying interpretations in estimation or categorization of reserves and in the date of the estimate.

Trans-Canada submitted that the additional 2.2 trillion cubic feet of gas it sought authorization to remove from the Province is therefore surplus to the needs of Alberta.

(2) Views of Interveners

None of the interveners at the hearing submitted evidence respecting the meeting of Alberta's 30-year requirements for gas and the permit commitments. The Utility Companies submitted that they have no objection to granting the application if the Board finds, using the method of surplus assessment under which the application was filed, that there are sufficient volumes of established reserves surplus to the needs of the Province. The Utility Companies added that they would have no objections if the surplus assessment for this application was modified in accordance with their suggestions at the recent hearing of the application of the Alberta Division of the Canadian Petroleum Association to modify the Board's policy respecting applications made under The Gas Resources Preservation Act, 1956.

(3) Views of the Board

The Meeting of Alberta's long term requirements (June 1, 1969 to May 31, 1999). The 30-year gas requirements for delivery to the markets within the Province (Alberta requirements discussed in Appendix C have been estimated at some 15.7 trillion cubic feet. The peak day requirement in the 30th year is estimated to be some 3.5 billion cubic feet. The fields now connected to and supplying Alberta's requirements together with their remaining reserves

as of May 31, 1969, which total 6.4 trillion cubic feet, are shown in Table D-1. Thirty times the requirements of the first year of the period (taken as the 12 months starting June, 1969) is 8.1 trillion cubic feet. The contractable requirements, defined under the Board's policy set forth in OGCB 69-D[1] as the greater of 30 times the requirements of the first year of the period under consideration or the remaining reserves in those fields connected to and supplying Alberta requirements, are therefore 8.1 trillion cubic feet.

The contractable requirements of the 30-year period have increased by 0.7 trillion cubic feet over the contractable requirements of the 30-year period considered in OGCB Report 68-A[2]. This increase is higher than would normally be expected and occurs because the requirements for the first year of the period considered in OGCB Report 68-A were underestimated with respect to shrinkage and fuel consumption at the existing plants for the reprocessing of pipe line gas.

Table D-1 shows also the Board's interpretation of the reserve-delivery ratio of each of the fields and the average reserve-delivery ratio of the group of fields supplying Alberta requirements. The reserves are classified in the table between major reserves, oil field gas, and small reserves plus reserves supplying small utilities. The reserve-delivery ratio

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

(2) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

is the initial gas in place adjusted for surface losses divided by the initial fully developed marketable gas deliverability. The ratios have been updated to take account of changes in reserves of pools, additional deliverability data and new discoveries.

The Board believes it is reasonable to assume that the deliverability characteristics of the 1.7 trillion cubic feet (8.1 - 6.4 = 1.7) of additional reserves needed to supply the contractable requirements will be similar to those of the contractable reserves of 6.4 trillion cubic feet now connected to and supplying the Alberta requirements. On this basis, the Board estimates that of the total of some 8.1 trillion cubic feet needed to supply the contractable Alberta requirements, some 6,100 billion cubic feet will be produced during the 30-year period and the remaining unproduced portion will be capable of sustaining a peak day delivery of some 620 million cubic feet in the 30th year. Therefore, total deliveries of about 9,600 billion cubic feet (15,700 - 6,100 = 9,600) and a 30th-year peak day delivery of about 2,880 million cubic feet (3,500 - 620 = 2,880) will be required from other sources.

The actual quantities of gas necessary to provide these deliveries may be calculated using the formula method presented in Appendix E of OGCB Report 64-11[3]. With respect to the factors to be used in the formula, the Board believes that since

(3) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November 1964.

this gas must come in part from established gas reserves not now connected to local utilities nor authorized for removal from the Province and in part from gas reserves not yet developed, the factors should reflect the delivery characteristics of both of these sources of gas.

The Board has again reviewed the average reserve-delivery ratio to take account of changes which have occurred since the issuance of OGCB Report 68-A. It finds, as is illustrated in Table D-2, that the average reserve-delivery ratio of 2.0 previously used, remains applicable. The Board has also reviewed the average reservoir recovery factor of the gas in place adjusted for surface losses and finds the factor of 0.74 as used in OGCB Report 68-A to be appropriate. This particular recovery factor represents the fraction of the remaining marketable gas in place in the Province which will be recovered and is a fraction which declines as additional gas is produced.

The following is a detailed calculation of the gas reserves in billions of cubic feet necessary to meet Alberta's 30-year requirements:

From now connected sources and additional sources needed to supply the contractable requirements, for delivery during the period	6,100	
From additional sources for delivery during the period	9,600	
Total Alberta Requirements for delivery		15,700

From now connected sources and additional sources needed to supply the contractable requirements, to protect the 30th year peak(1)	2,000	
From additional sources to protect the 30th year peak(2)	3,000	
Total Alberta requirements for peak day protection		5,000
Total Alberta Requirements		20,700

(1) i.e. 8,100 - 6,100 = 2,000

(2) Determined as $R_p = 1.3\ FP_n - (1-K)\ (1.3\ FP_n + A_1S)$

$$= 1.3\ (2.0)\ (2880) - (1 - 0.74)$$

$$1.3\ (2.0)\ (2880) + 9,600$$

$$= 7,488 - 4,443 = 3,045;\ \text{say } 3,000 \text{ billion cubic feet}$$

<u>The Remaining Permit Commitments.</u> The permit commitments remaining at May 31, 1969, are shown in Appendix C to be some 25.9 trillion cubic feet before adjustments for heating value and deficiencies in reserves in certain permits.

The fields included in each of the permits are shown in Table D-3. The table shows the Board's current estimate of the remaining reserves of marketable gas and the ratio of initial marketable gas in place to delivery capacity for each field. The table reflects changes in the remaining marketable reserves which have occurred since the preparation of OGCB Report 68-A and also incorporates revisions to reserve-delivery ratios resulting from additional data respecting pool deliverability.

In Table D-3, the remaining reserves of the Crossfield Field, for which Alberta and Southern, Trans-Canada and Westcoast all have permits, have been apportioned among them on the basis

of the Board's knowledge of their contracts. The entire remaining reserves which the Board attributes in Table A-1 to the Crossfield Rundle A Pool have been shown as named in the permit of Alberta and Southern since the Board believes it to be the only permittee with contracts for gas from the pool. For a similar reason, the Cardium solution gas and the reserves in the Crossfield Basal Quartz G Pool and the Crossfield Rundle D Pool have been included in the Trans-Canada permit. The reserves attributed in Table A-1 to all other pools in the Crossfield Field, where both Trans-Canada and Westcoast have gas under contract, are apportioned between these permittees in Table D-3. Westcoast has contracted for 1.0 trillion cubic feet of the gas in these pools and has first right to all deliverability until its contract volume is produced. Trans-Canada has the remainder under commitment subject to the Westcoast preference on deliverability. The gas will be available to Trans-Canada during the term of the Westcoast permit and at least in part following termination of the Westcoast permit. A deliverability study completed by the Board but not published in this report, indicates that on the basis of 1000 Btu per cubic feet gas, some 220 billion cubic feet can be delivered to Trans-Canada during the term of the Westcoast permit while still meeting the Westcoast delivery commitments. The study shows that an additional 235 billion cubic feet will be available to Trans-Canada following termination of the Westcoast permit but prior to the termination of the Trans-Canada permit. Trans-Canada has an additional 27 billion cubic feet of Crossfield

gas reserves under contract in the previously mentioned pools where no other purchase contracts exist. Accordingly, some 482 billion cubic feet of gas from the Crossfield Field have been included in Table D-3 as reserves in permit fields available to Trans-Canada. The remaining Crossfield reserves, other than in the Rundle A Pool which has been included in the Alberta Southern permit, have been included in the Westcoast permit.

Division of reserves between permittees or between permittees and provincial requirements has also been made for the Brazeau River, Caroline, Ferrier, Harmattan-Elkton, Homeglen-Rimbey, Hunter Valley, Jumping Pound West, Judy Creek, Pembina, Swan Hills, Swan Hills South, Sylvan Lake, Virginia Hills, Westerose South, Wayne-Rosedale, Provost and Medicine Hat Fields as well as a number of smaller fields. The division of reserves for these fields has been made on the basis of the Board policy spelled out in detail in OGCB 69-D.

At the hearing Trans-Canada requested that the Black Diamond Field be deleted from its Permit No. TC 68-8 as it no longer had gas under contract there. However, subsequent to the hearing it informed the Board that the Black Diamond Field had been considered further and that it wished to retain the field in its permit. It stated the producers in the field have been unable to sell their gas to the local utility, Canadian Western Natural Gas Company Limited, and that they wished to enter into firm contracts with Trans-Canada. It further stated that the local utility has no objection to Trans-Canada again contracting

to buy the gas and that Trans-Canada is prepared to purchase the gas. Under the conditions of Permit No. TC 68-8, which would be carried forward into a consolidated permit, the permittee must satisfy the Board by November 1, 1971, that it has entered into contracts to purchase gas from this field. In view of the above evidence the Board is satisfied the Black Diamond Field should remain in Trans-Canada's permit.

The results of the Board's analysis with respect to the meeting of the remaining permit commitments are shown in Table D-4. Columns 1 and 2 show respectively the remaining permit commitment and the maximum daily withdrawal authorized in each of the permits. These figures were obtained from Appendix C and have been adjusted where necessary for any deficiency in reserves in the fields, pools and areas named in the permit and also have been converted to the basis of 1000 Btu per cubic foot using the expected average heating value of the gas as it leaves the Province. This latter adjustment represents a change from the Board's previous reports where the adjustment to heating value was on a field basis. This change reflects the situation described in detail in the Board's Information Letter No. IL 69-8 dated May 13, 1969. The expiry date of each of the permits is shown in column 3. Columns 4 and 5 present, where applicable, the Board's current estimate of the total remaining marketable reserves and the reserve-delivery ratio (both from Table D-3) of the fields included in each permit. Column 6 shows the composite correction factor for each of the permittees' systems for which peak load

protection is provided, as determined from illustrative deliverability schedules prepared for this report. The estimated quantity of marketable gas in place required to meet the peak day commitments in the terminal year of each permit is shown where applicable in column 7. Column 8 shows the marketable gas equivalent of column 7. These values were obtained by deducting from column 7 the marketable gas equivalent of the gas that will remain in the reservoirs at abandonment. The total marketable gas required to meet the permit requirements, both deliveries and peak day, is shown in column 9. Columns 10 and 11 present the Board's estimate of the marketable gas in the fields in the permits in excess of the permit commitments, before and after the expiry date of each permit.

In the case of permits which could result in the removal of all the reserves in the permit fields or where no allowance for maximum day protection has been made by the Board, entries in columns 5 through 8, which support the calculation of marketable reserves required to meet the terminal year peak day, have been omitted.

The remaining commitment of the Westcoast Peace River Permits provides for an adjustment described more fully in OGCB Report 66-C[4] and in Permit No. WC 62-5, related to the delivery of gas from the Worsley Field and the meeting of future requirements of an iron ore processing industry in the Peace River area.

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(4) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. June, 1966.

The reserves credited to these permits have been adjusted having regard for these provisions, field deliverability and the withdrawals taken from the area to December 31, 1965. The provision for this market in the estimated Alberta requirements is discussed in detail in Appendix C of OGCB Report 68-A.

The particulars of Permit No. PG 64-1, which has been assigned to Trans-Canada and which Trans-Canada has applied to have consolidated with its principal permit in a new permit, are grouped with those of other small volume permits in the "other" entry in Table D-4. The remaining authorized withdrawal under Permit No. PG 64-1 was some 40 Bcf at May 31, 1969 and the permit fields contained some 46 Bcf of gas reserves.

Table D-4 shows that a total marketable gas reserve of 26.4 trillion cubic feet is required to meet the commitment of all subsisting permits of 26.1 trillion cubic feet. This represents a reduction since the preparation of OGCB Report 68-A which results not only because of production but because of the change in heating value calculations and a recalculation of the cushion gas required for the Westcoast Southern Alberta permit, Permit No. WC 59-3. The reduction in cushion gas associated with the Westcoast permit results from the new delivery study of the Crossfield Field incorporating recent adjustments to deliverability estimates and new information respecting contracts in the field. Since reserves of 28.4 trillion cubic feet are available in the permit fields, a surplus of 2.0 trillion cubic feet exist in the fields named in the permits. Several years before the end of the 30-year period, an additional 300 billion

cubic feet, the amount allowed to meet the terminal year peak day deliveries for the Westcoast Permit No. WC 59-3, will also become excess to the existing permit commitments.

The Gas Surplus to Alberta's Requirements and the Permit Commitments. The surplus calculation using the method recently adopted by the Board and discussed in detail in OGCB 69-D is illustrated in Table D-6.

The table shows that the Board's estimate of contractable reserves, the reserves within economic reach (43.9 trillion cubic feet) less the deferred reserves (5.1 trillion cubic feet) totals some 38.8 trillion cubic feet. The deferred reserves are listed in Table D-7 which shows that the entire 5.1 trillion cubic feet is expected by the Board to become marketable within 30 years. The contractable requirements include 8.1 trillion cubic feet needed to supply the Alberta contractable requirements (6.4 trillion cubic feet of which are now connected to supply Alberta's requirements) and 26.4 trillion cubic feet to meet the permit commitments. The comparison of the contractable reserves and the contractable requirements results in a contractable surplus of 4.3 trillion cubic feet.

The table also shows that the remaining Alberta requirements total some 12.6 trillion cubic feet. These are made up of some 9.6 trillion cubic feet which the Board believes will have to be delivered during the 30-year period and some 3.0 trillion cubic feet which the Board estimates will be necessary to provide for the 30th-year peak day.

The remaining and future reserves available to meet these Alberta requirements are shown to total some 19.3 trillion cubic

feet. These are made up of 5.1 trillion cubic feet of deferred gas which the Board believes will be available within the 30-year period, some 2.2 trillion cubic feet of reserves now beyond economic reach but which the Board believes will be within economic reach within 30 years, some 0.3 trillion cubic feet allocated to protect peak day requirements in certain permits but available within 30 years and 11.7 trillion cubic feet of future reserves.

The detail of the deferred reserves which will become marketable within 30 years is shown in Table D-7. The Board studies indicate that of the total deferred reserves of some 5.1 trillion cubic feet, about 2.8 trillion cubic feet will be deliverable during the 30-year period and the remaining 2.3 trillion cubic feet will be available to assist in the meeting of the 30th-year peak day.

The 2.2 trillion cubic feet of reserves now beyond economic reach but expected to be available within 30 years was obtained by taking 75 per cent of the reserves now considered beyond economic reach. The Board expects that essentially all of this gas will be deliverable during the 30-year period.

The 0.3 trillion cubic feet available from the cushion gas portion of the permit requirements results from the detailed delivery schedules prepared for the Crossfield Field. The schedules also show that approximately 0.1 trillion cubic feet of this cushion gas will be deliverable during the 30-year period and that some 0.2 trillion cubic feet will be available towards the 30th-year peak day requirements.

Prior to the inclusion in the future surplus calculation of all of the reserves available within 30 years from the above mentioned three categories, the Board has made one further test. Detailed studies indicate that some 5.1 trillion cubic feet of these reserves are actually deliverable within 30 years and that the remaining 2.5 trillion cubic feet will be available to meet the 30th-year peak day requirement. Since the 2.5 trillion cubic feet is less than the 3.0 trillion cubic feet shown earlier in Table D-6 as required from other sources to meet the 30th-year peak day, the Board believes that the total of these reserves, some 7.6 trillion cubic feet, should be included in remaining reserves.

The future reserves to be considered have been determined in Appendix B as 11.7 trillion cubic feet. Table D-6 shows that the total remaining reserves exceed the total remaining requirements by 6.7 trillion cubic feet.

TABLE D-1

RESERVES AND RESERVE-DELIVERY RATIOS OF FIELDS
SUPPLYING ALBERTA'S REQUIREMENTS FOR GAS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
MAJOR RESERVES			
BEAVERHILL LAKE - FORT SASKATCHEWAN		383	0.8
BOW ISLAND		27	0.9
CARBON		122	0.9
FAIRYDELL-BON ACCORD		77	0.7
FOREMOST		18	0.8
JUDY CREEK		31	1.0
JUMPING POUND		297	3.7
JUMPING POUND WEST		661	7.7
MEDICINE HAT		342	3.6
MORINVILLE		58	1.6
OKOTOKS		119	4.0
PADDLE RIVER		154	1.2
SARCEE		109	1.5
ST. ALBERT-BIG LAKE		50	1.7
TURNER VALLEY		197	4.6
VIKING KINSELLA		399	1.8
WAYNE-ROSEDALE		133	1.0
WESTLOCK		203	1.2
WORSLEY		150	0.4
	TOTAL	3,530	
	WEIGHTED AVERAGE		1.7
OIL FIELD GAS			
ACHESON		20	10.3
ACHESON EAST		4	6.0
BONNIE GLEN		273	27.4
FENN-BIG VALLEY		10	20.8

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-1 (CONTINUED)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
GLEN PARK		10	28.0
JUDY CREEK		177	35.2
LEDUC-WOODBEND		29	5.0
PEMBINA		831	36.0
REDWATER		44	26.8
SAMSON		2	3.8
SIMONETTE		89	27.5
STETTLER		2	6.0
SWAN HILLS		239	40.7
SWAN HILLS SOUTH		123	42.7
VIRGINIA HILLS		34	34.8
WIZARD LAKE		108	30.9
	TOTAL	1995	
	WEIGHTED AVERAGE		25.9
SMALL RESERVES PLUS RESERVES SUPPLYING SMALL UTILITIES			
ACHESON		23	1.2
ALDERSON		18	9.1
ALEXANDER		11	0.5
ATHABASCA		6	1.5
ATHABASCA EAST		2	0.6
ATIM		2	0.3
BANTRY		35	13.2
BEAVER CROSSING		1	0.3
BITTERN LAKE		99	2.2
BONNIE GLEN		7	3.5
BONNYVILLE		1	0.1
BROOKS		3	9.5
CALAIS		21	1.0
CALLING LAKE		37	2.2
CASTOR		3	0.3
CHARLOTTE LAKE		2	0.4
COLD LAKE		2	0.4

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
CRAIG LAKE	1	0.3
DOWLING LAKE	1	0.3
DUVERNAY	1	0.6
EDWAND	3	0.1
ELK POINT	1	1.0
ELLERSLIE	1	0.1
ETHEL LAKE	2	0.4
ETZIKOM	13	1.7
EXCELSIOR	36	1.0
FLAT	10	1.5
FORT KENT	2	0.1
GLEN PARK	5	1.2
HAIRY HILL	10	0.6
HAMELIN CREEK	33	1.2
HANNA	11	2.5
HEART RIVER	2	0.1
HERCULES	30	2.3
HOLMBERG	22	1.3
KILLAM NORTH	18	0.9
KNOPCIK	12	1.0
LAC LA BICHE	7	1.0
LEAHURST	13	1.4
LEGAL	2	1.0
LINDBERGH	12	1.0
LLOYDMINSTER	2	0.5
MURIEL LAKE	5	0.4
NORMANDVILLE	39	5.0
OBERLIN	-	1.0
PROVOST	8	1.7
REDLAND	15	0.6
RYCROFT	12	1.6
SADDLE HILLS	52	5.5
SEXSMITH	4	0.7

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
ST. PAUL	-	0.8
STRATHMORE	15	2.5
STROME	1	0.8
STURGEON LAKE SOUTH	2	0.5
THORHILD	11	1.0
TWEEDIE	50	0.7
WAINWRIGHT	17	1.0
WATTS	1	0.9
WHITELAW	45	1.9
WILDMERE	17	1.0
WILLINGDON	12	0.7
WINNIFRED	6	3.0
WIZARD LAKE	3	0.5
WOKING	12	0.9
TOTAL	850	
WEIGHTED AVERAGE		1.0
TOTAL RESERVES CONNECTED AND SUPPLYING REQUIREMENTS	6,375	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.4

TABLE D-2

SUMMARY OF RESERVES AND

AVERAGE RESERVE-DELIVERY RATIO FOR ALL

RESERVES IN THE PROVINCE

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE RESERVES AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
RESERVES NOW SUPPLYING ALBERTA'S REQUIREMENTS (SEE TABLE D-1)	6,375	2.4
FIELDS INCLUDED IN PERMITS (SEE TABLE D-3)	28,455	1.9
FIELDS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED (2) (SEE TABLE E-1)	1,476	3.9
REMAINING ESTABLISHED RESERVES (3)	10,454	1.9
TOTAL RECOVERABLE RESERVES IN THE PROVINCE	46,760	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.0

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

(2) DOES NOT INCLUDE THOSE FIELDS IN PERMIT NO. PG. 64-1

(3) INCLUDES DEFERRED RESERVES AND RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH.

TABLE D-3

MARKETABLE RESERVES AVAILABLE AND RESERVE-DELIVERY RATIOS OF THE FIELDS INCLUDED IN PERMITS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE DELIVERY RATIO[1] BCF/MMCFD
ALBERTA AND SOUTHERN GAS CO. LTD. (PERMIT NO. AS 69-5)		
BELLOY	79	2.8
BERLAND RIVER	297	1.2
BIGORAY	32	1.8
BIGSTONE	316	3.3
BRAZEAU RIVER	134	3.8
CAROLINE	53	1.7
CARSON CREEK	255	0.8
CARSON CREEK NORTH	175	24.2
CROSSFIELD	872	1.2
EAGLESHAM	65	4.6
FERRIER	14	7.5
FOX CREEK	126	1.8
GOLD CREEK	404	4.1
HARMATTAN-ELKTON	155	3.3
HOMEGLEN-RIMBEY	133	0.7
HUNTER VALLEY	20	3.0
JUDY CREEK, SWAN HILLS, SWAN HILLS SOUTH, AND VIRGINIA HILLS	281	37.9
KAYBOB	432	1.4
KAYBOB SOUTH	97	2.4
MARLBORO	40	5.1
MINNEHIK-BUCK LAKE	495	1.6
OPEN CREEK	36	4.7
PEMBINA	193	4.3
PINE CREEK	105	1.5
PINE NORTH-WEST	188	13.7

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
SIMONETTE	60	2.3
STURGEON LAKE SOUTH	72	14.6
SUNDRE	33	9.3
SYLVAN LAKE	7	2.3
TANGENT	64	3.6
WASKAHIGAN	107	4.1
WATERTON	1,953	3.1
WESTEROSE SOUTH	446	0.5
WESTWARD HO	-	-
WILDCAT HILLS	477	5.9
WILDHORSE CREEK	56	4.6
WILLESDEN GREEN	154	12.9
WILSON CREEK	52	2.2
WINDFALL	498	1.0
TOTAL	8,976	
WEIGHTED AVERAGE		1.8
CANADIAN-MONTANA PIPELINE COMPANY (PERMIT NO. CM 54-1 AND CM 61-2)		
ADEN	12	2.1
BLACK BUTTE	49	3.4
COMREY	27	2.8
KNAPPEN	17	2.0
MANYBERRIES	6	1.1
PAKOWKI LAKE	10	1.4
PENDANT D'OREILLE	124	2.0
SMITH COULEE	3	1.1
TOTAL	248	
WEIGHTED AVERAGE		2.0
TRANS-CANADA PIPE LINES LIMITED (PERMIT NO. TC 68-8)		
ALDERSON	335	6.0
AMISK	9	2.9
ARMADA	9	2.2
ATLEE-BUFFALO	95	2.6
BASHAW	34	0.3

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
BASSANO	14	1.4
BELLIS	36	4.1
BERRY	8	1.7
BIG BEND	68	3.2
BINDLOSS	227	3.4
BLACK DIAMOND	19	5.0
BLUE RIDGE	29	2.2
BOYLE	14	1.0
BRAZEAU RIVER	637	2.8
BRUCE	26	1.5
BURNT TIMBER	258	10.2
CAROLINE	127	2.0
CARSTAIRS	669	1.7
CASSILS	9	5.6
CASTOR	26	12.7
CESSFORD	762	1.8
CHESTERMERE	28	6.0
CHIGWELL	33	1.3
CONNORSVILLE	55	3.6
COUNTESS	185	0.7
CRAIGEND	188	1.8
CROSSFIELD	482	2.5
CROSSFIELD EAST	709	7.1
DRUMHELLER	69	1.2
EDSON	1,951	2.0
ENCHANT	44	0.4
EQUITY	38	2.9
ERSKINE	41	1.6
FENN WEST	7	0.5
FERRIER	309	10.1
FIGURE LAKE	32	0.9
FLAT	124	1.3
GARRINGTON	8	5.6

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
GHOST PINE	769	1.9
GILBY	691	2.0
GOODWIN	17	8.2
GREENCOURT	139	1.3
HACKETT	45	1.4
HARMATTAN EAST	56	6.6
HARMATTAN ELKTON	39	0.9
HOLMGLEN-RIMBEY	399	0.7
HUGHENDEN	5	4.4
HUNTER VALLEY	30	4.4
HUSSAR	333	0.8
INNISFAIL	79	6.1
JARROW	9	1.8
JUMPING POUND WEST	69	5.9
KILLAM	15	0.5
LATHOM	4	1.7
LECKIE	1	0.7
LITTLE BOW	28	0.7
LONE PINE CREEK	302	3.5
LONG COULEE	14	0.6
LOOKOUT BUTTE	447	4.6
MALMO	49	1.0
MARTEN HILLS	804	1.7
MCMULLEN	7	1.1
MEDICINE HAT	291	5.7
MEDICINE RIVER	281	3.4
MITSUE	211	58.9
NEVIS	667	1.8
NEWELL	2	0.5
NEW NORWAY	11	1.4
OLDS	218	2.9
OYEN	32	3.2

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
PELICAN	14	6.1
PINCHER CREEK	294	12.2
PREVO	33	3.5
PRINCESS	121	2.0
PROVOST	696	1.7
QUIRK CREEK	555	5.6
RANIER	3	0.7
RETLAW	89	1.9
RICH	12	1.2
ROWLEY	73	2.7
SCANDIA	4	2.9
SEDALIA	100	12.3
SEDGEWICK	26	1.8
SEIU LAKE	25	5.5
SIBBALD	24	2.1
STANDARD	20	5.4
SUNDRE	12	3.3
SUNNYNOOK	14	1.3
SWALWELL	5	14.0
SYLVAN LAKE	448	2.5
THREE HILLS CREEK	163	4.2
TROCHU	10	3.3
TURIN	30	2.2
TWINING NORTH	48	4.4
VERGER	37	0.8
VULCAN	30	1.6
WAYNE-ROSEDALE	180	1.0
WESTEROSE	77	21.0
WESTEROSE SOUTH	552	0.5
WHITECOURT	117	1.0
WILDHORSE CREEK	56	5.5
WIMBORNE	151	1.2

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
WINTERING HILLS	69	2.5
WOOD RIVER	15	1.4
TOTAL	17,280	
WEIGHTED AVERAGE		1.8
WESTCOAST TRANSMISSION COMPANY LIMITED (PERMIT NO. WC 59-3)		
CROSSFIELD	865	2.4
IRRICANA	11	4.1
SAVANNA CREEK	171	15.1
TOTAL	1,047	
WEIGHTED AVERAGE		4.1
WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD. (PERMIT NO. WC 52-1 AND WC 62-5)		
BRAEBURN	59	4.2
GORDONDALE	16	1.7
POUCE COUPE	16	1.6
POUCE COUPE SOUTH	41	1.2
WORSLEY	- 33	0.4
TOTAL	99	
WEIGHTED AVERAGE		1.2
WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD. (PERMIT NO. WC 61-4		
BOUNDARY LAKE SOUTH	56	1.4
OTHERS		
ANTELOPE	17	0.9
ESTHER	30	0.9
HALLIDAY (2)	3	1.4
MEDICINE HAT	655	2.3
RED COULEE	1	3.3
RICHDALE (2)	25	1.9

TABLE D-3 (CONTINUED)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
WILDUNN CREEK (2)		18	3.3
	TOTAL	749	
	WEIGHTED AVERAGE		2.1
TOTAL (ALL FIELDS)		28,455	
WEIGHTED AVERAGE (ALL FIELDS)			1.9

(2) INCLUDED IN PERMIT NO. PG 64-1 WHICH TRANS-CANADA HAS APPLIED TO HAVE CONSOLIDATED WITHIN PERMIT NO. TC 68-8.

TABLE D-4

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS [1]

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT (2)									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD. (AS 69-5)	8,218	1,239	31/10/93	8,976					8,218	758	758
CANADIAN-MONTANA PIPE LINE COMPANY	248	98	15/3/86	248					248	-	-
TRANS-CANADA PIPE LINES LIMITED (3)	16,136	2,745	31/10/93	17,280					16,136	1,144	1,144
WESTCOAST TRANSMISSION COMPANY LIMITED (3) (SOUTHERN ALBERTA)	755	164	29/2/84	1,047	4.1	0.8	554	292	1,047	-	292
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	155	196	31/12/79	155					155	-	-
OTHERS	618	176		749				23	641	108	131
TOTALS	26,130	4,678		28,455				315	26,445	2,010	2,325
ROUNDED TOTALS	26,100	4,700		28,400				300	26,400	2,000	2,300

(1) ALL FIGURES ARE AS OF MAY 31, 1969.

(2) ON THE BASIS OF THE HEATING VALUE OF THE GAS AS IT LEAVES THE PROVINCE.

(3) TRANS-CANADA DELIVERIES FROM CERTAIN CROSSFIELD POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE D-5

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AS OF FEBRUARY 28, 1969 AS ESTIMATED BY TRANS-CANADA

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1,000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES				
NOW CONSIDERED WITHIN ECONOMIC REACH		44.3		
LESS: DEFERRED		6.4		
TOTAL CONTRACTABLE RESERVES			37.9	
CONTRACTABLE REQUIREMENTS				
CONTRACTABLE ALBERTA REQUIREMENTS		7.7		
PERMIT REQUIREMENTS –				
TO MEET COMMITMENTS	26.6			
TO MEET TERMINAL YEAR PEAK	0.5			
		27.1		
TOTAL CONTRACTABLE REQUIREMENTS			34.8	
CONTRACTABLE SURPLUS				+3.1
REMAINING REQUIREMENTS				
TOTAL ALBERTA REQUIREMENTS FOR DELIVERY	14.9			
ALBERTA REQUIREMENTS FOR THIRTIETH YEAR PEAK	5.1			
TOTAL ALBERTA REQUIREMENTS		20.0		
LESS: AVAILABLE FROM CONTRACTABLE RESERVES		7.7		
TOTAL REMAINING REQUIREMENTS			12.3	
REMAINING AND FUTURE RESERVES				
FROM DEFERRED GAS AVAILABLE WITHIN THE 30-YEAR PERIOD		5.7		
FROM RELEASE OF RESERVES REQUIRED TO PROTECT PEAK DAY IN PERMITS		0.5		
FROM RESERVES WHICH WILL BECOME WITHIN ECONOMIC REACH DURING THE 30-YEAR PERIOD		1.9		
FROM APPRECIATION OF ESTABLISHED RESERVES AND FUTURE DISCOVERIES		5.4		
			13.5	
FUTURE SURPLUS				+1.2
OVERALL SURPLUS				+4.3

TABLE D-6

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF MAY 31, 1969

AS ESTIMATED BY THE BOARD

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

<u>CONTRACTABLE RESERVES</u>					
NOW CONSIDERED WITHIN ECONOMIC REACH			43.9		
LESS: DEFERRED			5.1		
TOTAL CONTRACTABLE RESERVES				38.8	
<u>CONTRACTABLE REQUIREMENTS</u>					
CONTRACTABLE ALBERTA REQUIREMENTS			8.1		
PERMIT REQUIREMENTS:					
TO MEET COMMITMENTS		26.1			
TO MEET TERMINAL YEAR PEAK DAY		0.3			
TOTAL CONTRACTABLE REQUIREMENTS				34.5	
CONTRACTABLE SURPLUS					4.3
<u>REMAINING REQUIREMENTS</u>					
TOTAL ALBERTA REQUIREMENTS FOR DELIVERY	15.7				
LESS: DELIVERIES FROM CONTRACTABLE RESERVES	6.1				
DELIVERIES REQUIRED FROM OTHER SOURCES		9.6			
TOTAL ALBERTA REQUIREMENTS FOR THIRTIETH YEAR PEAK DAY	5.0				
LESS: AVAILABLE FROM CONTRACTABLE RESERVES	2.0				
REQUIRED FROM OTHER SOURCES TO MEET THIRTIETH YEAR PEAK DAY		3.0			
TOTAL REMAINING REQUIREMENTS			12.6		
<u>REMAINING AND FUTURE RESERVES</u>					
FROM DEFERRED GAS AVAILABLE WITHIN 30 YEARS		5.1			
FROM RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH		2.2			
FROM RESERVES PROVIDING FOR TERMINAL YEAR PEAK DAY IN PERMITS		0.3			
FROM GAS NOT YET ESTABLISHED		11.7			
TOTAL REMAINING AND FUTURE RESERVES			19.3		
FUTURE SURPLUS					6.7

TABLE D-7

DEFERRED RESERVES
(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

POOL MARKETABLE WITHIN 30 YEARS	MARKETABLE RESERVES AT MAY 31, 1969 BCF
BANTRY MANNVILLE A	31
BONNIE GLEN D-3A	378
CLIVE D-2 & D-3	44
GOLDEN SPIKE D-3A	248
HARMATTAN EAST RUNDLE	1,049
HARMATTAN-ELKTON RUNDLE C	1,062
JOARCAM VIKING	52
KAYBOB CADOMIN B	64
KAYBOB SOUTH BEAVERHILL LAKE A	[illegible]
LEDUC-WOODBEND BLAIRMORE	51
LEDUC-WOODBEND D-2A	47
LEDUC-WOODBEND D-3A	381
SWALWELL PEKISKO	39
SYLVAN LAKE JURASSIC A	30
WESTEROSE D-3	102
OTHER SMALL AND CONFIDENTIAL RESERVES	25
TOTAL DEFERRED RESERVES	[illegible]

APPENDIX E

THE APPLICATION FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE EFFECT THE AUTHORIZATION WOULD HAVE ON SURPLUS

Trans-Canada is now authorized under Permit No. TC 68-8 and Permit No. PG 64-1 to remove from the Province 19,245 billion cubic feet of gas, of which some 3,200 billion cubic feet have been removed to May 31, 1969. It applied for an increase of 2,200 billion cubic feet in the quantity authorized under Permit No. TC 68-8 which represents a net increase of 2,155 billion cubic feet since 45 billion cubic feet is the permit volume of Permit No. PG 64-1 being consolidated with Permit No. TC 68-8. This would increase the total to 21,400 billion cubic feet of gas, at a maximum daily rate of 2,910 million cubic feet from the fields now named in its permits and from 21 new fields and areas. The volumes before and after adjustment to the basis of 1,000 Btu per cubic foot are compared below:

	As is Basis	1,000 Btu Basis
Total Trans-Canada permit volume, May 31, 1969, Bcf.	19,245	19,514
Addition applied for, Bcf	2,155	2,179
Trans-Canada permit volume if the application is granted, Bcf	21,400	21,693
Removed at May 31, 1969, Bcf	3,239	3,333
Remaining Trans-Canada permit volumes if the application is granted, Bcf	18,161	18,360
Present maximum daily rate, MMcfd	2,725	2,755
Maximum daily rate applied for, MMcfd	2,910	2,942

All volumes subsequently referred to in this Appendix respecting the Trans-Canada permit are on the basis of 1,000 Btu per cubic foot.

Trans-Canada has applied for an increase of its remaining authorized withdrawals from 16,181 billion cubic feet as of May 31, 1969, to 18,360 billion cubic feet (19,514 - 3,333 = 16,181). Table E-1 shows proposed additions of fields or areas in the Trans-Canada permit, fields or areas in Permit No. PG 64-1 which Trans-Canada applied to have consolidated with Permit No. TC 68-8, and the Board's current estimate of the remaining reserves of marketable gas and the reserve delivery ratio for each of the fields listed.

The Board has assessed the contract data respecting the Strachan Field provided at the hearing of the subject application and also at the later hearing of an application by Consolidated to remove gas from the Province. By combining the submitted evidence respecting contracts, and its own gas reserves interpretation for the Strachan Field, the Board has estimated that of the total marketable reserve of 1,540 billion cubic feet, Trans-Canada has approximately 901 billion cubic feet under contract. This quantity has been included in Table E-1 as reserves in the Strachan Field available to Trans-Canada. The table also includes 50 per cent, or 44 billion cubic feet, of the reserves in the Ricinus Field where both Trans-Canada and Consolidated have contracts.

The results of the Board's analysis with respect to the meeting of permit commitments and the additional volumes applied

for by Trans-Canada are presented in Table E-2, which is similar in form to the previously discussed Table D-4. The only changes have been to replace the Trans-Canada entry with a new entry reflecting therein, the consolidation of Permit No. PG 64-1 and the additional quantities applied for and reserves available in the fields from which the applicant proposed to remove gas, and to delete Permit No. PG 64-1 from the 'other' entry.

The Trans-Canada entry in the table suggests that the remaining volume applied for of 18,360 billion cubic feet is less than the Board's estimate of total remaining reserves of fields which would be included in Trans-Canada's permit of 18,802 billion cubic feet. The latter figure includes only that portion of reserves which the Board considers available to Trans-Canada in those pools where more than one permittee has gas purchase contracts.

Since Alberta's requirements and the other permit volumes can be separately accommodated from other Alberta reserves, the Board believes the entire amount applied for may be included in the quantity considered for removal from the Province. However, no assurance can be given that the gas can be produced during the full term of the permits at the respective requested maximum daily rates.

Table E-2 further shows that, with the inclusion of the volumes applied for by Trans-Canada, the remaining permit commitments would total some 28.3 trillion cubic feet and the reserves required to meet these commitments would total some 28.6 trillion cubic feet.

Table E-3 presents the calculation of the amount of gas that would be surplus to Alberta's requirements and the permit commitments if the application of Trans-Canada is granted. Most of the figures used in the preparation of the table have been taken directly from Table D-6. The exception to this is the contractable permit requirements which are taken from Table E-2 and include the volumes applied for by Trans-Canada.

Table E-3 shows that on the basis of the Board's estimates, there would remain a contractable surplus of 2.1 trillion cubic feet if Trans-Canada were authorized to remove the additional volumes applied for. The table also shows that the remaining and future reserves would exceed the remaining requirements by some 6.7 trillion cubic feet. Increased Alberta requirements of some 130 billion cubic feet over the 30-year period would likely result from approval of Trans-Canada's application due to additional extraction of natural gas liquids at the Empress gas reprocessing plants and increased fuel requirements of The Alberta Gas Trunk Line Company Limited. However, a substantial surplus would still remain after allowance for these anticipated additional requirements.

TABLE E-1

MARKETABLE RESERVES AND RESERVE-DELIVERY RATIOS

OF ADDITIONAL FIELDS

(ALL VOLUMES AT 1,000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
FIELDS APPLIED FOR BY TRANS-CANADA		
ALIX (SOLUTION GAS)	1	10.0
BANTRY (SOLUTION GAS)	24	11.7
BASSANO	14	1.4
BELLIS	5	0.2
BIRCH	6	2.5
CLIVE (SOLUTION GAS)	19	24.7
JENNER	41	1.4
JUMPING POUND WEST	32	5.0
KITSIM	7	2.7
LONG COULEE	2	1.1
MIKWAN	6	3.2
MOOSE	55	10.3
OBED	159	10.4
PARFLESH	9	1.7
PLAIN	13	1.3
RANFURLY	9	1.3
RICINUS	44	23.3
STRACHAN	901	3.6
WHISKEY	111	13.4
WILLESDEN GREEN	7	6.9
WINNIFRED	11	1.2
TOTAL	1,476	
WEIGHTED AVERAGE		3.9

TABLE E-1 (CONTINUED)

MARKETABLE RESERVES AND RESERVE-DELIVERY RATIOS

OF ADDITIONAL FIELDS

(ALL VOLUMES AT 1,000 BTU PER CUBIC FOOT)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
FIELDS CURRENTLY IN PERMIT NO. PG 64-1			
HALLIDAY		3	1.4
RICHDALE		25	1.9
WILDUNN CREEK		18	3.3
	TOTAL	46	
	WEIGHTED AVERAGE		2.3

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY

TABLE E-2

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS INCLUDING THE TRANS-CANADA APPLICATION [1]

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT [2]									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DAY OF PERMIT	RESERVES IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD. (AS 69-5)	8,218	1,299	31/10/93	8,976					8,218	758	758
CANADIAN-MONTANA PIPELINE COMPANY	248	98	15/3/86	248					248	-	-
TRANS-CANADA PIPE LINES LIMITED (3)	18,360	2,942	31/10/94	18,802					18,360	442	442
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA) (3)	755	164	29/2/84	1,047	4.1	0.8	554	292	1,047	-	292
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	155	196	31/12/79	155					155	-	-
OTHERS	578	166		703				23	601	102	125
TOTALS	28,314	4,862		29,931				315	28,629	1,302	1,617
ROUNDED TOTALS	28,300	4,900		29,900				300	28,600	1,300	1,600

(1) ALL VOLUMES ARE AS OF MAY 31, 1969, EXCEPT FOR THE ADJUSTMENTS FOR THE TRANS-CANADA APPLICATION.

(2) ON THE BASIS OF THE HEATING VALUE OF THE GAS AS IT LEAVES THE PROVINCE.

(3) TRANS-CANADA DELIVERIES FROM CERTAIN CROSSFIELD POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE E-3

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF MAY 31, 1969

AS ESTIMATED BY THE BOARD

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES					
Now considered within economic reach			43.9		
Less: Deferred			5.1		
Total Contractable Reserves				38.8	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta requirements			8.1		
Permit requirements - To meet remaining commitments		28.3			
- To meet terminal year peak day in certain permits		0.3			
Total Contractable Requirements				36.7	
CONTRACTABLE SURPLUS					2.1
REMAINING REQUIREMENTS					
Total Alberta requirements for delivery	15.7				
Less: Deliveries from contractable reserves	6.1				
Deliveries required from other sources		9.6			
Total Alberta requirements for thirtieth year peak day	5.0				
Less: Available from contractable reserves	2.0				
Required from other sources to meet thirtieth year peak day		3.0			
Total Remaining Requirements			12.6		
REMAINING AND FUTURE RESERVES					
From deferred gas available within 30 years		5.1			
From reserves now considered beyond economic reach		2.2			
From reserves providing for terminal year peak day in certain permits		0.3			
From gas not yet established		11.7			
Total Remaining and Future Reserves			19.3		
FUTURE SURPLUS					6.7

APPENDIX F

FORM OF PERMIT

IN THE MATTER of the Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Trans-Canada Pipe Lines Limited authorizing the removal of gas from the Province

PERMIT NO. TC 69-9

WHEREAS Trans-Canada Pipe Lines Limited (hereinafter called "the Permittee") is removing gas from the Province under the authority of Permit No. TC 68-8 and Permit No. PG 64-1; and

WHEREAS the Permittee has applied to the Oil and Gas Conservation Board for an increase in the volumes of gas that it may remove or cause to be removed from the Province, and for amendment and consolidation of its permits; and

WHEREAS the Board upon inquiry into and hearing of the application has found that the Permittee is a person who appears to have made arrangements to purchase gas within the Province and who proposes to remove such gas from the Province and that the provisions of The Gas Resources Preservation Act, 1956, affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of this Permit for the removal of gas from the Province is in the public interest having regard to the present and future needs of persons within the Province and to the established reserves and

the trends in growth and discovery of reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by an Order in Council, numbered O.C. , and dated

THEREFORE, the Oil and Gas Conservation Board, pursuant to the provisions of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956, hereby grants a permit to Trans-Canada Pipe Lines Limited, and hereby authorizes the removal of gas from the Province, subject to the regulations and orders made pursuant to the provisions of the said Act and to the terms and conditions prescribed in this Permit as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this Permit shall be operative for a term commencing on the date hereof and ending on October 31, 1994.

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed

(a) during the term of the Permit and together with gas removed under Permit No. TC 54-1, Permit No. TC 59-2, Permit No. TC 60-3, Permit No. TC 60-4, Permit No. TC 64-5, Permit No. TC 64-6, Permit No. TC 67-7 and Permit No. TC 68-8 and under Permit No. PG 64-1 both before and after assignment, 21,400,000,000,000 cubic feet, nor

(b) during any consecutive 24-hour period or any consecutive 12-month period ending October 31,

rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 2,910,000,000 cubic feet and in a 12-month period such rates shall not exceed 932,000,000,000 cubic feet.

3. The quantity of gas that may be removed from the Province in accordance with clause 2, subclause (b), during any 12-month period ending October 31, may be augmented by any part of the quantity by which gas removed from the Province under this Permit, Permit No. TC 64-6, Permit No. TC 67-7, Permit No. TC 68-8 or Permit No. PG 64-1 in the last preceding four year period ending October 31, shall have been less than the sum of the annual volumes stipulated in clauses 2 of the permit or permits to be so removed in the four-year period and which has not, in the meantime, been removed from the Province as an augmentation authorized by this clause, but nothing herein authorizes the removal of gas from the Province in any consecutive 24-hour period or during the term of the Permit in excess of the volumes stipulated for such periods in clause 2.

4. Notwithstanding the provisions of clause 2, subclause (b), the Permittee, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized by said sub-clause (b).

5. The Permittee, subject to clause 8, may remove or cause to be removed from the Province under the Authority of this Permit, only gas produced from the following pools, fields and areas:

Alderson Field

Alix Field

Amisk Field

Armada Field

Atlee-Buffalo Field

Bantry Field

Bashaw Field

Bassano Field

Bellis Field

Berry Field

Big Bend Field

Bindloss Field

Birch Field

Black Diamond Field

Blueridge Field

Boyle Field

Brazeau River Field

Bruce Field

Burnt Timber Field

Caroline Viking A Pool

Caroline Viking E Pool

Caroline Basal Mannville A Pool

Carstairs Field

Cassils Field

Castor Field

Cessford Field

Chestermere Field

Chigwell Field

Clive Field

Connorsville Field

Countess Field

Craigend Field

Crossfield Field

Crossfield East Field

Drumheller Field

Edson Field

Enchant Field

Equity Field

Erskine Field

Fenn West Field

Ferrier Field

Figure Lake Field

Flat Field

Garrington Mannville A Pool

Garrington Leduc A Pool

Ghost Pine Field

Gilby Field

Goodwin Field

Greencourt Field

Hackett Field

Halliday Field

Harmattan East Field

Harmattan-Elkton Rundle A Pool

Homeglen-Rimbey Field

Hughenden Field
Hunter Valley Field
Hussar Field
Innisfail Field
Jarrow Field
Jenner Field
Johnson Field
Jumping Pound West Field
Killam Field
Kitsim Field
Lathom Field
Leckie Field
Little Bow Field
Lone Pine Creek Field
Long Coulee Field
Lookout Butte Field
Malmo Field
Marten Hills Field
McMullen Field
Medicine River Field
Mikwan Field
Mitsue Field
Moose Field
Nevis Field
Newell Field
New Norway Field
Obed Field

Olds Field
Oyen Field
Parflesh Field
Pelican Field
Pincher Creek Field
Plain Field
Prevo Field
Princess Field
Provost Field
Quirk Creek Field
Rainier Field
Ranfurly Field
Retlaw Field
Rich Field
Richdale Field
Ricinus Field
Rowley Field
Scandia Field
Sedalia Field
Sedgewick Field
Seiu Lake Field
Sibbald Field
Standard Field
Strachan Field
Sundre Basal Mannville A Pool
Sundre Basal Mannville B Pool
Sunnynook Field

Swalwell Field

Sylvan Lake Field

Three Hills Creek Field

Trochu Field

Turin Field

Twining North Field

Verger Field

Vulcan Field

Wayne-Rosedale Field

Westerose Field

Westerose South Field

Whiskey Field

Whitecourt Field

Wildhorse Creek Field

Wildunn Creek Field

Willesden Green Field

Wimborne Field

Winnifred Field

Wintering Hills Field

Wood River Field

The area in the Medicine Hat Field being north of Sections 1 to 6 inclusive, in Township 15, and in Ranges 1 to 3 inclusive, West of the 4th Meridian, excepting therefrom Section 7, Township 15, Range 2, West of the 4th Meridian.

6. (1) The Permittee shall satisfy the Board prior to November 1, 1970, or such later date as the Board upon application

by the Permittee may stipulate, that

(a) the Permittee has entered into gas purchase contracts to purchase gas from the Bruce Field, the Flat Field, the Jarrow Field and the Killam Field or from a substantial part of each of the fields; and

(b) the Permittee has elected to cause the construction of the Bruce-Birch Lake Line or has advised the sellers under the contracts referred to in subclause (a) that it is proceeding to cause the Marten Hills Line to be constructed; and

(c) arrangements have been completed for construction of facilities necessary for the transportation of gas produced from the said fields and that effective removal of gas produced from the said fields shall commence on or before February 1, 1971, unless upon application by the Permittee a later date is stipulated by the Board.

(2) If the Permittee fails to satisfy the Board at the time and regarding the matters set out in subclause (1), the Board may, at a public hearing, reconsider the circumstances and may delete from this Permit any or all of the fields referred to in subclause (1) and reduce the volumes referred to in clause 2 accordingly.

7. (1) The Permittee shall satisfy the Board prior to November 1, 1971, or such later date as the Board upon application by the Permittee may stipulate, that

(a) the Permittee has entered into gas purchase contracts to purchase gas from the Amisk Field, Big Bend Field, Black Diamond Field, Castor Field, Chestermere Field, Hamilton Lake Field, Hughenden Field, Jumping Pound West Field, McMullen Field, Pelican Field, Provost Field and Turin Field or from a substantial part of each of the fields; and

(b) arrangements have been completed for construction of facilities necessary for the transportation of gas produced from the said fields and that effective removal of gas produced from the said fields shall commence on or before February 1, 1972, unless upon application by the Permittee a later date is stipulated by the Board.

(2) If the Permittee fails to satisfy the Board at the time and regarding the matters set out in subclause (1), the Board may, at a public hearing, reconsider the circumstances and may delete from this Permit any or all of the fields referred to in subclause (1) and reduce the volumes referred to in clause 2 accordingly.

8. Gas acquired in Alberta by the Permittee, in exchange for equal volumes of gas, adjusted for any difference in higher heating value, produced from pools, fields or areas named in clause 5, may be removed from the Province under the authority of this Permit.

9. The Permittee shall remove or cause to be removed pursuant to this Permit only such gas as is delivered to it through facilities

of The Alberta Gas Trunk Line Company Limited at the interconnections of their pipe lines in the North-east quarter of Section 11, Township 20, Range 1, West of the 4th Meridian and in the North-east quarter of Section 11, Township 38, Range 1, West of the 4th Meridian.

10. (1) All gas removed from the Province pursuant to this Permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located at the points at which gas is delivered in accordance with clause 9 by The Alberta Gas Trunk Line Company Limited to the Permittee.

(2) The specific gravity and higher heating value of all gas received by the Permittee through the facilities of The Alberta Gas Trunk Line Company Limited shall be measured by or on behalf of the Permittee at the points at which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

11. Subject to section 14 of the said Act, all quantities of gas for the purpose of this Permit shall be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

12. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this Permit.

13. The Permittee will supply gas from the pipe line of The Alberta Gas Trunk Line Company Limited at a reasonable price to

any community or consumer within the Province, or to any public utility requiring gas for such a community or consumer, that is willing to take delivery of gas at a point on the pipe line, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

14. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 13, and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

15. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, competent regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

16. Permit No. TC 68-8 and Permit No. PG 64-1 are rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of ,A.D. 1969.

OIL AND GAS CONSERVATION BOARD

G. W. Govier

Chairman